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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	Docket No. E-04204A-06-0783

NOTICE OF FILING DIRECT TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimonies of Marylee Diaz, Cortez, CPA, William A. Rigsby, CRRA and Rodney L. Moore, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 28th day of June 2007.

Daniel W. Pozefsky
Attorney

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By Ernestine Gamble
Ernestine Gamble
Secretary to Daniel Pozefsky

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss certain issues pertaining to operating income, rate base, and to present my recommendations on these issues. RUCO witness Rodney L. Moore also presents recommendations on these same ratemaking elements, as well as sponsors RUCO's overall revenue requirement recommendation. RUCO witness William A. Rigsby presents recommendations regarding cost of capital.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. Procedures performed included the issuance of seven sets of data requests, review of other parties' data requests, conversations with Company personnel, and the review of prior ACC Decisions pertaining to this Company.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-4.

Q. Please summarize the issues and recommendations you address in your testimony.

A. My testimony addresses the following issues:

GENERATATION

* Capacity – Black Mountain Generating Station
* Purchased Power and Fuel Adjustment Clause (PPFAC)

RATE BASE

* Construction Work in Progress
* Accumulated Deferred Income Taxes
* Working Capital

OPERATING INCOME

* Miscellaneous Service Fees
* Bad Debt Expense
* Year-end Accruals
* Administrative and General Expense Capitalization
* Construction Work in Progress Property Taxes
* Corporate Cost Allocations
* Valencia Turbine Fuel

OTHER ISSUES

* Demand-side Management (DSM)

GENERATION

Black Mountain Generating Station

Q. What is UNS Electric's current source of generation?

A. Currently, UNS Electric obtains its power through a full requirements Power Supply Agreement (PSA) with Pinnacle West Capital Corporation (PWCC). This contract will expire on June 1, 2008. UNS Electric also owns 65 MW of generation capacity in Santa Cruz County that is used for reliability must run circumstances.

Q. How does UNS plan to supply its customers with power once the PWCC contract expires?

A. According to the Company, it has developed a Procurement Plan that provides for a mix of market power purchases, resource acquisitions, and supply contracts to provide the capacity, energy, and reserves necessary to serve its customers. UNS Electric has already secured 100 MW of power supply contracts that it procured pursuant to a Request for Proposal (RFP) process. These contracts will become effective June 1, 2008 when the PWCC contract expires. The Company also plans to purchase a 90 MW generating station, the Black Mountain Generating Station, which its affiliate UniSource Energy Development Company (UEDC) plans to build.

Q. What changes is the Company requesting in its base rates and PPFAC mechanism to accommodate the changes in its power supply that will take place when the PWCC contract expires in June 2008?

A. The Company is proposing a "stepped in" rate increase that would take place in two phases. Step 1 would reflect any change in rates necessitated by the adjusted test year ended June 30, 2006 and Step 2 would incorporate the investment and expenses associated with the planned purchase of the Black Mountain Generating Station in June 2008. The Company proposes the following modifications to the PPFAC:

1) Change the current PPFAC, which is a fixed rate, to an automatically adjusting rate based on a twelve-month rolling average;

2) Confirmation that the PPFAC will include all costs in FERC accounts 501, 547, 555, and 565, as well as the cost of credit support associated with purchased power procurement and hedging;

3) Authorization to accrue carrying costs on the bank balance at a rate equal to LIBOR plus 1%; and

4) Change the PPFAC Bank Threshold to $10 million for both under- or over- collected bank balances and add a defined recovery period.

Q. Does RUCO agree with these proposed changes?

A. No, not in their entirety.

Q. Please discuss RUCO's position on the proposed stepped-in rate increase for the Black Mountain Generating Station.

A. RUCO opposes this proposal. The proposal is contrary to nearly every ratemaking principle to which Arizona adheres. It violates the known and measurable principle, the matching principle, the historical test year principle, and the used and useful principle. The proposal also would circumvent the higher level of scrutiny typically afforded related party transactions and, in large part, pre-determine prudency.

Q. Please explain.

A. The level of investment as well as the operating costs of the Black Mountain Generating Station are not known and measurable at this juncture since construction, let alone operation of the plant, has not even begun. Likewise, the proposal by definition does not provide a proper matching of costs because both the incremental costs as well as the cost savings resulting from the transaction are unknown. The investment is projected to take place more than two years outside of the test year and thus violates the historical test year principle. Neither is the proposed plant used and useful since it has not even been built yet. Further, the proposed transaction is a related party transaction which requires a high level of scrutiny to insure there are no related party abuses, and that it is equivalent to a transaction that would happen at an arm's length. Such scrutiny is not possible at this time since the plant is not built, the costs are unknown, and the transaction has not occurred. Lastly, approval of the Company's proposed Step 2 rates would result in piecemeal ratemaking, as it would consider only the incremental cost changes resulting from the acquisition of the generating station, but not changes in any of the other ratemaking elements.

Q. What does RUCO recommend regarding the issue of the generating station and stepped-in rates?

A. RUCO recommends that the Commission deny the Company's request for stepped-in rates. As discussed above, this proposal is contrary to nearly every ratemaking principle. Probably the worst aspect of this proposal, however, is that it would require the Commission to grant rate base approval of an asset prior even to its existence. The very notion of this is unprecedented. Further, RUCO has concerns that premature rate base approval of this proposed asset might affect any future determination of prudency.

Q. How does RUCO propose that the Company recover its generation costs once the PWCC contract expires in the absence of stepped-in rates?

A. RUCO recommends the current PPFAC be modified in this proceeding so that it is capable of giving the Company an opportunity to recover its power costs, while still protecting ratepayers from large fluctuations in power costs. RUCO recognizes that at some point in time if and when the Black Mountain Generating Station actually exists, and its costs are known and measurable, that acquisition of this asset may be a good investment. However, that determination is impossible at this juncture. In the interim, once the proposed plant enters service, the Company can enter into a short term PPA with its affiliate UEDC to acquire the output of the plant and then file a request for acquisition and rate base recognition of this asset in a rate case, thus avoiding the violation of all the ratemaking principles just discussed.

Purchased Power and Fuel Adjustor Clause (PPFAC)

Q. Do you agree with the Company that some modifications to its existing PPFAC are necessary to accommodate the expiration of the PWCC contract in June 2008?

A. Yes. The current PPFAC is a non-adjusting mechanism since the existing PWCC power contract carries a fixed rate. However, once that contract expires, UNS Electric's power costs will no longer be fixed and the PPFAC will require more flexibility in order for the Company to remain whole.

Q. Do you agree with the PPFAC that the Company is proposing?

A. No, not in its entirety. While it is necessary that the PPFAC be modified so it can adjust to changes in prices, ratepayers at the same time need to be protected from wild market swings, any potential related-party abuses, and poor management decisions. Thus, the flexibility of the new PPFAC needs to be tempered with adequate protections for ratepayers.

Q. What aspects of the Company's proposed PPFAC do you agree with?

A. RUCO agrees with the following aspects of the Company's proposed PPFAC:

1) The new PPFAC will be self-adjusting based on a twelve-month rolling average of fuel and purchased power costs;

2) PPFAC will include costs from FERC accounts 501, 547, 555, 565;

3) The bank threshold will be set at $10 million for both under- and over-recoveries;

4) Carrying costs on the bank balance will be accrued at LIBOR plus 1%.

Q. What aspects of the Company's proposed PPFAC do you disagree with?

A. RUCO disagrees with the following aspects of the Company-proposed PPFAC:

1) Recovery of Letter of Credit Fees (LOC) through the PPFAC;

2) Automatic instatement of a surcharge or surcredit when the bank balance exceeds the $10 million threshold;

3) No cap on the amount the PPFAC can automatically adjust; and

4) Lack of incentive in the structure of the PPFAC for the Company to mitigate costs.

Q. Please discuss the first of the shortcomings of the Company's proposed PPFAC.

A. The purpose of a PPFAC is to allow the utility to recover fluctuations in its cost of fuel and purchase power. Historically, adjustors of this type have been authorized because fuel and purchased power costs represent a high percentage of a utility's total operating costs, these costs tend to be volatile in nature, and are, in part, beyond the control of management. LOC fees however do not meet any of the above-cited reasons for automatic adjustment and, as such, should be included in the Company's other operating expenses, and not flowed through the PPFAC.

Q. Please discuss the second shortcoming of the Company's proposed PPFAC.

A. The Company's proposed PPFAC would allow the Company to automatically, with no Commission oversight, begin recovering the PPFAC bank balance once it exceeds the $10 million threshold. RUCO believes this provision circumvents the Commission's authority to regulate the timing and manner in which excess bank balances are recovered from ratepayers. It is important that the Commission retain its ability to set the terms of excess PPFAC bank balances on a case-by-case basis in order to protect the public.

Q. Please discuss the third shortcoming of the Company's proposed PPFAC.

A. The Company proposed PPFAC has no cap limiting the amount by which adjustor can change over an annual period. This creates the potential for rate shock in a period of wildly escalating fuel and purchased power costs. The lack of a cap also exposes the Company's ratepayers to market risks, for which the Company is already compensated through its return on equity. While the use of a twelve-month rolling average somewhat tempers the magnitude of annual changes in the PPFAC rate, RUCO does not believe it provides adequate protections to ratepayers from unpredictable markets.

Q. Has the Commission set caps on other utilities' fuel and purchased power adjustors?

A. Yes. APS has a 4 mil annual cap on its Power Supply Adjustor (PSA). The Commission voted for renewal of this extra protection in APS' recent rate case. Because APS owns power plants to serve most of its load, APS' exposure to fluctuating costs is primarily related to the fuel its generating plants use. The Commission still deemed the extra protection of a cap warranted. UNS Electric will be exposed to potentially greater fluctuations than APS, given that it must secure its power primarily in the market.

Q. Please discuss the fourth shortcoming of the Company's proposed PPFAC.

A. The proposed PPFAC provides in large part a blank check for the Company to recover its fuel and purchased power cost, whatever these costs should be. The automatic flow-though characteristics of the proposed PPFAC provide no incentive for the Company to control and contain its fuel and purchased power costs. This is particularly disturbing considering that the Company, at least in the short run, will be exposed nearly 100% to the purchased power markets. It is even more disturbing considering the probability of related party transactions for the procurement of power.

Q. What are RUCO's recommendations to remedy the four shortcomings in the Company's proposed PPFAC?

A. RUCO recommends the following modifications to the Company's proposed PPFAC:

1) Deny recovery of LOC fees in the PPFAC and limit PPFAC eligible costs to FERC accounts 501, 547, 555, and 565;
2) Deny automatic adjustment of the PPFAC when the $10 million threshold is reached, and require the Company to instead file an application for recovery/refund of the excess balance for Commission consideration;
3) Set a cap of 6 mils per year on the amount the PPFAC can increase. Amounts over the cap would accrue to the bank balance; and
4) Require a 90/10 sharing between ratepayers and shareholders of any fuel and purchase power costs that exceed the base cost of fuel and purchased power.

Q. With these modifications, does RUCO believe that the dual objective of allowing the Company an opportunity to recover its prudently incurred fuel and purchased power costs and protecting the ratepayer from wide rate swings and poor management decisions is met?

A. Yes. The cap will temper wide rate swings in the event that the twelve-month rolling average by itself cannot. The cap provides an extra protection that I believe is absolutely imperative given the fact that, at least in the short run, the Company will be subject primarily to the market for its power supply. Further, requiring Commission approval of recovery of any accrued bank balances that exceed the $10 million threshold, rather than automatic flow through, allows the Commission discretion in determining the terms and amounts of recovery given the then-current circumstances. Finally, the 90/10 sharing mechanism provides the Company with real motivation to control its power supply costs and make wise and prudent choices in procuring power. These safeguards are imperative for an electric distribution company that, at least in the short run, will be virtually totally dependent on purchased power.

RATE BASE

Rate Base Adjustment #3 – Construction Work in Progress (CWIP)

Q. Is UNS Gas requesting the inclusion of its test year-end CWIP balance in rate base?

A. Yes. The Company claims that this extraordinary treatment of CWIP is warranted for it to maintain its financial integrity, to fund its rapid growth, to mitigate regulatory lag, to make up for its large negative acquisition adjustment, and to prolong the period between rate cases.

Q. Is this the accepted ratemaking treatment for CWIP?

A. No. Utility regulation routinely excludes CWIP from rate base because it does not meet the used and useful ratemaking standard, which requires that assets actually be in service and providing a benefit to ratepayers before their inclusion in rates. Utility accounting already allows the accrual of interest, in the form of an Allowance for Funds Used During Construction (AFUDC), on the CWIP balances. These interest accruals are ultimately recovered over the life of the asset once it enters service through depreciation expense. Thus, rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery.

Q. Are you aware of any instances where utility commissions have made an exception to standard ratemaking treatment and included CWIP in rate base?

A. Yes, but only as result of extraordinary circumstances. During the 1970's and 1980's many utility commissions made an exception and allowed CWIP in rate base. In most cases the exception was made due to the drain on cash flow caused by construction of nuclear plants. Due to the large outlays of cash required to build a nuclear plant coupled with the very long lead time before such plants enter service, many utilities became unable to service their debt due to lack of cash flows. The inclusion of CWIP was considered an emergency measure as well as a temporary measure. It historically has not been a routine ratemaking mechanism. In fact, Arizona Public Service Company was recently denied a similar request for the recognition of CWIP in rate base.[1]

Q. Do the reasons cited by the Company that warrant rate base treatment of CWIP meet the "extraordinary circumstance" standard just discussed?

A. No. First, the Company's argument that CWIP in rate base is necessary to maintain financial integrity is without merit. Other than in extraordinary circumstances, this Commission has never allowed CWIP in rate base and Arizona utilities have not lost their financial integrity as a result. Likewise, the Company's growth argument is without merit as growth has a positive

[1] Decision No. ___, Docket Nos. E-01345A-05-0816, E-01345A-05-0826, AND E-01345A-05-0827.

effect on the Company, generating more revenue and cash flow. Regulatory lag always has been a characteristic of rate of return regulation. It does not all of a sudden create a need to put CWIP in rate base. Regulatory lag is a two way street that works both for and against the Company. Types of regulatory lag that benefit the Company are plant retirements, accumulated depreciation, and expired amortizations. In all these instances the Company continues to earn a return on and recovery of assets that have already been recovered. Thus, the notion that we need to mitigate the regulatory lag that does not favor the Company, such as the Company suggests in its CWIP in rate base argument, yet continue to allow the effects of regulation that do benefit the Company, is clearly biased. The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit. The Company currently has no CWIP in rate base and even so it has been ten years since its last rate case in 1995. In fact, no large Arizona utilities that I am aware of have CWIP in rate base, yet these utilities are not filing back-to-back rate cases. Further, in my experience the Commission has favored, rather than disapproved of, utilities coming in for regular rate reviews. Finally, the Company's argument that the large negative acquisition it agreed to when it acquired Citizens gas properties now justifies the inclusion of CWIP in rate base, is disingenuous at best.

Q. Why do you say this argument is disingenuous at best?

A. At the time of the settlement agreement, the Company touted the negative acquisition as an attractive feature of the agreement that would provide substantial benefits to ratepayers. Company witness, and then-UniSource Vice President Steven Glaser stated the following in his testimony in that proceeding:

> A further benefit of the settlement is that Citizens' gas customers will have use of approximately $30.7 million of facilities and Citizens' electric customers will have use of approximately $93.6 million of facilities that they will never have to pay for because UniSource has agreed not to seek recovery of the negative acquisition adjustments.[2]

It is hardly appropriate to now use the benefit of the negative acquisition adjustment as a reason to increase rates by including CWIP in rate base.

Q. What adjustment are you recommending?

A. I have decreased rate base by $10,761,154 to remove the Company-requested CWIP balances.

Rate Base Adjustment #4 – Accumulated Deferred Income Taxes – CIAC

Q. Have you reviewed the Company's test-year accumulated deferred income tax balances?

A. Yes. I have reviewed every item that comprises the test-year balance of $3,390,766 and the adjusted test-year balance of $1,154,741.

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[2] Rebuttal Testimony of Steven Glaser, Docket No. E-01933A-02-0914, page 2.

Q. Do you agree with these balances?

A. Yes, for the most part. However, there is one deferred tax asset balance of $888,390 with which I disagree.

Q. Why do you disagree with the inclusion of this deferred tax item in rate base?

A. According to the Company, this deferred tax asset balance is attributable to CIAC taxes that were self-paid by UNS Electric. However, the Company has no related CIAC liability on its books and records. My review of the Company's Schedule B-1, FERC Form 1, and the test-year general ledger shows no FERC account 271 for CIAC.

Q. What adjustment are you recommending?

A. I have removed the CIAC related deferred tax asset of $888,390 from rate base. It is inappropriate to charge ratepayers for deferred taxes related to CIAC when the Company has not credited its rate base for the CIAC liabilities that created the tax asset.

Rate Base Adjustment #5 – Accumulated Deferred Income Taxes – A&G Capitalization

Q. Are you proposing any other adjustments to the Company's proforma ADIT balance?

A. Yes. As will be discussed in the Operating Income section of my testimony, I have made an adjustment (Operating Adjustment #10) to remove a double count in capitalized A&G expense. This adjustment will impact ADIT and, accordingly, I have increased the proforma test year ADIT balance by $116,258 to reflect this impact.

Rate Base Adjustment #6 – Working Capital

Q. Have you reviewed the Company's working capital calculations?

A. Yes. The Company's working capital request is comprised of a thirteen-month average balance for its prepayment and material and supplies accounts, and its cash working capital request is based on a lead/lag study.

Q. Do you agree with the Company's methodology?

A. Yes. Further, I have reviewed the Company's individual lag day calculations and find them to be reasonable. The only difference between the Company's calculation and RUCO's is the different level of expense recommendations. These adjustments result in a net increase in cash working capital of $1,615,255.

OPERATING INCOME

Operating Adjustment #1 – Miscellaneous Service Fees

Q. Is the Company requesting a change in its miscellaneous service fees?

A. Yes. The Company has prepared cost-of-service studies of its connect/reconnect and establishment/re-establishment fees. These studies indicate the cost to perform these services exceeds the current tariffs for these services.

Q. Do you agree that these service fees should be set at cost-of-service?

A. Yes. These services should be priced at their actual cost. If they are not, it will have the effect of having the general body of ratepayers subsidizing the customers who utilize these services.

Q. Are the Company's proposed tariffs for these services priced at cost-of-service?

A. Yes and no. Interestingly, the Company's proposed tariffs for establishment and connect services during business hours are at the cost indicated in its cost-of-service studies, however, it has priced these services for after business hours at a price below cost.

Q. Are you proposing an adjustment to the proposed tariffs for after business hours services?

A. Yes. These services need to be set at cost so the customers requesting these services are the ones that will pay the cost of these services. As shown on Schedule MDC-3, I have increased the Company's $75 fee for after hours service to $125, which is the cost indicated in the Company's cost-of-service study. This adjustment increases test year revenue by $48,648.

Operating Adjustment #6 - Bad Debt Expense

Q. Has the Company made an adjustment to increase its actual test year recorded bad debt expense?

A. Yes. The Company has calculated an average bad debt write-off percentage based on the ratio between its 2004 and 2005 account receivable write-offs and its 2004 and 2005 retail revenue. This calculation results in a bad debt write-off percentage of .36792%, which is then applied to adjusted test year revenues of $157,516,223, rendering proforma bad debt expense of $579,538.

Q. Do you agree with this calculation?

A. No. The Company's calculation overstates proforma bad debt expense because it improperly uses balance sheet accrual information to quantify test year expenses. Specifically, the Company uses balance sheet accrual account receivable write-offs to establish its bad debt expense ratio. These accruals in 2004 and 2005 were significantly higher than the amount of bad debts actually expensed on the Company's test-year income statement. Thus, when this bad debt accrual ratio is applied to test-year proforma revenues it overstates the proforma amount of bad debt expense.

Q. What adjustment have you made?

A. I have recalculated the bad debt percentage using the ratio between the actual bad debt expensed during the test year to actual test-year retail revenue. This calculation, unlike the Company's calculation, is internally consistent because it utilizes the amount of bad debts actually expensed to derive adjusted bad debt expense. As shown on Schedule MDC-3, this decreases test year expenses by $203,038.

Operating Adjustment #7 – Fleet Fuel Expense

Q. Has the Company proposed an adjustment to its test year level of fuel expense for its fleet of vehicles?

A. Yes. The Company has proposed an adjustment to annualize its fuel expense to reflect the additional employees it has included in its payroll annualization adjustment.

Q. Do you agree with this adjustment in concept?

A. Yes. The Company's payroll annualization has the effect of increasing payroll expense to recognize payroll attributable to the year-end level of employees for the entire year. The Company's proposed fleet fuel adjustment recognizes the additional fuel expense attributable to these additional employees, as well as annualizes the average cost of gasoline. Thus, conceptually, the adjustment is necessary to match these two items of expense.

Q. Do you agree with the Company's calculation of the fleet fuel expense adjustment?

A. No. The Company's calculation was based on the average fuel prices during June, July, and August of 2006. Pursuant to a data request, the Company has provided more recent data showing the average gasoline price for the first five months of 2007. Using this more recent data my adjustment results in an annualized level of fuel expense that is $53,250 less than the annualized level proposed by the Company.

Operating Adjustment #9 - Year End Accruals

Q. Has the Company proposed an adjustment to correct certain out-of-period expenses?

A. Yes. The Company has identified a number of expenses recorded in the test year that relate to prior periods as well as identified certain expenses that were recorded outside the test year that were incurred during the test year.

Q. Do you agree with this adjustment?

A. Yes. It is appropriate to adjust the test year to accurately reflect those costs that incurred during the test year. However, the Company failed to reverse one of the prior period expenses that it had identified. This expense was incurred in April 2004 but not recorded to expense until August 2005. Thus, this $6,256 expense should not be included in the test year expenses as it relates to a period prior to the test year. Accordingly, I have reduced test year expense by this amount.

Operating Adjustment #10 - A&G Capitalization

Q. Please discuss the Company's proposed adjustment to test-year Administrative and General Expense capitalization.

A. The Company proposes an adjustment that increases test year expenses by $301,187 to reclassify costs that were capitalized during the test year to the income statement.

Q. Do you agree with this adjustment?

A. No. This adjustment will result in a double count of these costs. During the test year the Company accounted for it's A&G expenses using a capitalization rate of 52.6%. Using this rate, UNS Electric capitalized

$663,975 in A&G expenses. These amounts now reside in either the Company's plant-in-service accounts or its CWIP accounts. Both of these accounts will earn a return in the proposed rates either through the return on rate base in the case of plant-in-service or through AFUDC in the case of CWIP. Further, the test-year capitalized A&G expenses of $663,975 will be recovered dollar for dollar through depreciation expense. Thus, the test-year accounting for these capitalized costs provides for their recovery in this rate case. If the Company's adjustment to reclassify some of these capitalized expenses to the income statement is accepted, ratepayers will be required to pay for them twice – once through depreciation expenses and return on rate base and again as part of operating expenses.

Q. What adjustment have you made?

A. I have reversed the Company's proposed adjustment and decreased proforma operating expenses by $301,187 to remove the double count.

Q. Are there any other problems with this proposed adjustment in addition to the double count?

A. Yes. In addition to the double count, the Company has quantified its proposed adjustment by using the new capitalization ratio it calculated for its gas division, as opposed to the new ratio it's calculated for the electric division. Correction of this error would increase the proposed capitalization rate from 28.7% to 31%. This error is somewhat moot however, since the entire adjustment appropriately should be reversed to remove the double count.

Operating Adjustment #11 – CWIP Property Taxes

Q. Has the Company proposed an adjustment for property taxes related to its CWIP balances?

A. Yes. The Company proposes to increase test-year expenses for both depreciation on its CWIP balances and property tax on its CWIP balances. I will not discuss the CWIP deprecation portion of this adjustment because it is addressed by Mr. Moore in his testimony. The property tax portion of this adjustment represents only the adjustment attributable to CWIP, and the Company has proposed a separate property tax adjustment for its overall plant. This separate property tax adjustment, related to the overall plant, is also addressed in the testimony of Mr. Moore.

Q. Do you agree with the property tax portion of the Company's CWIP expense adjustment?

A. No. As discussed previously in the rate base section of my testimony, CWIP is not used and useful and, as such, historically has not been afforded rate base recognition. Likewise, the property tax attributable to CWIP balances should not be included in test-year operating expense. My adjustment removes the Company's proforma CWIP property taxes of $239,697 from test-year expenses.

Operating Expense Adjustment #12 – Corporate Cost Allocations

Q. Did you review the Company's Corporate Cost allocations?

A. Yes. During the test year UNS Electric received $613,584 in corporation cost allocations from Tucson Electric Company (TEP). After making a proforma adjustment to that amount, the Company is requesting corporate cost allocations totaling $710,736.

Q. Have you reviewed these cost allocations?

A. The Company provided a list of each individual charge that comprised the test-year corporate cost allocations. I reviewed each cost item as well as requested copies of the invoices supporting certain allocations. I considered this review an important aspect of RUCO's audit, since the allocated expenses are related party transactions that require a high level of scrutiny.

Q. As a result of your review are you recommending an adjustment?

A. Yes. I found three categories of expenses that are not appropriately recovered from ratepayers. These categories and the amounts allocated are as follows:

1) Meals and Entertainment – Discretionary $13,773
2) Travel – Meals and Entertainment $6,799
3) Advertising - Corporate Relations/Communications $92,410

UNS Electric's test-year share of these costs was 8.86%, or $10,010. Accordingly, I have removed these costs from test-year expenses.

Operating Adjustment #14 - Valencia Turbine Fuel

Q. Has the Company proposed a proforma adjustment to include the cost of fuel to operate its Valencia Turbines in base rates?

A. Yes. The Company has increased test-year operating expenses by $266,198 to include the Valencia fuel costs.

Q. Why were there no costs included in the test year for Valencia fuel?

A. According to the Company's response to RUCO data request 2.03, the cost of the Valencia fuel was included in the test year PPFAC.

Q. Why is the Company transferring the recovery of this fuel expense from the PPFAC to base rates?

A. According to the Company's response to RUCO data request 2.03, the proforma adjustment was made to increase the base cost of fuel, yet the response also indicates that these fuel costs would be passed through the Company's proposed PPFAC.

Q. Won't this result in a double-count?

A. Yes. RUCO, like the Company, is also proposing a PPFAC that automatically adjusts based on a twelve-month rolling average. Thus, acceptance of the Company's proposed operating expense adjustment would allow recovery through base rates *and* the PPFAC.

Q. What adjustment are you recommending?

A. I have removed the $266,198 from proforma operating expenses. UNS Electric will recover these fuel costs through the new adjusting PPFAC.

Operating Adjustment #21 – Outside Services – DSM

Q. Are you proposing any adjustment for test year outside services?

A. Yes. During the test year the Company paid ECOS Consulting $49,920 to develop the Residential New Construction DSM Program (Energy Smart Homes). Going forward, the Company has proposed that the cost of all DSM programs be recovered through a DSM surcharge adjustor. I have therefore removed the ECOS Consulting costs from test year expenses because on a going forward basis these costs will be recovered through the DSM surcharge, and therefore will not recur as a part of base rates.

OTHER ISSUES

Demand Side Management (DSM)

Q. Is the Company proposing any changes to its existing DSM programs and expenditures?

A. Yes. During the test year the Company spent approximately $460,000 on two DSM programs; Low Income Weatherization and Energy Smart

Homes. The Company is proposing to more than double its DSM expenditures to $950,000. The additional funding would be used to expand the two existing DSM programs and to add a Residential HVAC Retro fit program, Shade Tree program, Education and Outreach program, Direct Load Control program, and Commercial Facilities Efficiency program. The Company requests the $950,000 funding be recovered through a surcharge that would true-up annually.

Q. Does RUCO support this proposal?

A. Yes. RUCO recognizes the value and desirability of cost-effective DSM programs. The additional funding proposed will allow for enhancement of existing programs, new programs, and consequently more savings through DSM. The more the cost of energy and generation increase, the more valuable a resource DSM becomes.

Q. Does RUCO believe the surcharge should be allowed to collect more than the requested $950,000, if spent on cost effective DSM programs?

A. Yes. To the extent that any given DSM program is approved through the Commission pre-approval process the prudent and cost-effective expenditures of the program should be recoverable through the adjustor surcharge.

Q. Does RUCO support the combining of the UNS Electric and Gas DSM programs, as proposed by the Company?

A. Yes. RUCO supports the promotion of efficiency and economies of scale where practicable.

Rules and Regulations Changes

Q. Is the Company proposing any changes to its rules and regulations of service?

A. Yes. The Company has proposed several changes to its rules and regulations of service. RUCO takes issue with one of the proposed changes.

Q. Which proposed change does RUCO take issue with.

A. The Company proposes to shorten the period of time customers have to pay their gas bills before a late fee is assessed from 15 days to 10 days, and to shorten the time customers have to pay a past due bill prior to notice of shut off from 30 days to 15 days.

Q. Why does RUCO take issue with these proposed changes?

A. The proposed changes are unreasonable. The proposed payment due dates are so short that a UNS Gas customer on vacation could foreseeably come home and find their electricity shut-off. Since electricity is a vital service to most, a more flexible payment schedule should prevail.

As a regulated utility, UNS Electric already receives a working capital allowance to bridge differences between receipt of revenues and payment of expenses, and should not have to impose unreasonable payment terms on its customers. RUCO recommends the Commission deny the proposed changes in payment due dates.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION:	University of Michigan, Dearborn B.S.A., Accounting 1989
CERTIFICATION:	Certified Public Accountant - Michigan Certified Public Accountant – Arizona
EXPERIENCE:	Audit Manager Residential Utility Consumer Office Phoenix, Arizona 85007 July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States.

Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Utility Company	Docket No.	Client
Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service

Utility Company	Docket No.	Client
United Cities Gas Company	176-717-U	Kansas Corporation Commission
General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office
Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office
Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company & Northern States Power Company	G-01970A-98-0017 & G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company & Mummy Mountain Water Company	W-01303A-98-0678 & W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company & Nicksville Water Company	W-02465A-98-0458 & W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation & ONEOK, Inc.	G-01551A-99-0112 & G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications & Citizens Utilities Company	T-01051B-99-0737 & T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office
Black Mountain Sewer Corporation	SW-02361A-05-0657	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-05-0816	Residential Utility Consumer Office
Arizona-American Water Company	WS-1303A-06-0014	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-05-0650	Residential Utility Consumer Office
UNS Gas, Inc.	G-04204A-06-0463 et al.	Residential Utility Consumer Office

TABLE OF CONTENTS TO RUCO SCHEDULES

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER UNS	$5,650,559	SCH. B-5, PG. 1
2	MATERIALS & SUPPLIES PER RUCO	5,650,559	SCH. B-5, PG. 1
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER UNS	351,825	SCH. B-5, PG. 1
5	PREPAYMENTS PER RUCO	351,825	SCH. B-5, PG. 1
6	ADJUSTMENT	0	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER UNS	(2,634,713)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(1,019,458)	SCHEDULE MDC-
9	ADJUSTMENT	1,615,255	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT (See RLM-4, Column (G))	$1,615,255	SUM LINES 3, 6 & 9

LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION		(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses:						
	Non-Cash Expenses						
1	Bad Debts Expense		$ 579,538	$ (203,038)	$ 376,500	0	$ -
2	Depreciation		15,594,232	(4,375,714)	11,218,518	0	$ -
3	Amortization		(3,781,658)	3,781,658	-	0	$ -
4	Deferred Income Taxes		494,521	-	494,521	0	$ -
5	Total Non-Cash Expenses		$ 12,886,633	$ (797,094)	$ 12,089,539		$ -
	Other Operating Expenses:						
6	Salaries & Wages (UNS Dir.Emp's)		$ 4,571,466	$ -	$ 4,571,466	23.33	$ 106,652,302
7	Incentive Pay (UNS Dir. Emp's)		98,247	(98,247)	-	267.00	-
8	Purchased Power		106,021,950	(266,198)	105,755,752	33.79	3,573,486,860
9	Transmission Other		7,009,878	-	7,009,878	40.67	285,091,738
10	Meter Reading		730,556	(774)	729,782	33.67	24,571,776
11	Customer Records & Collections		2,982,604	(92,900)	2,889,704	34.94	100,966,248
12	Office Supplies and Expenses		535,854	(40,614)	495,240	50.89	25,202,761
13	Injuries and Damages		512,417	(63,289)	449,128	70.52	31,672,495
14	Pensions and Benefits		1,172,133	(103,004)	1,069,129	51.37	54,921,159
15	Support Services - TEP(Dir. Labor)		5,631,155	-	5,631,155	44.77	252,106,809
16	Property Taxes		3,096,371	(649,598)	2,446,773	213.00	521,162,752
17	Payroll Taxes		348,088	(8,320)	339,768	19.87	6,751,190
18	Current Income Taxes		1,342,818	2,341,386	3,684,204	41.42	152,599,735
19	Interest on Customer Deposits		217,492	-	217,492	182.50	39,692,290
20	Other Operations and Maintenance		2,587,216	(749,803)	1,837,413	41.21	75,719,793
21	Total Other Operating Expenses		$136,858,245	$ 268,640	$137,126,885		$ 5,250,597,908
22	Total Operating Expenses		$149,744,878	$ (528,454)	$149,216,424		$ 5,250,597,908
	Other Cash Working Capital Elements:						
23	Interest on Long-Term Debt		$ 5,819,157	$ (499,676)	$ 5,319,481	90.22	$ 479,923,565
24	Revenue Taxes and Assessments		13,983,561	-	13,983,561	45.71	639,188,573
25	Total Other Cash Working Capital		$ 19,802,718	$ (499,676)	$ 19,303,042		$ 1,119,112,138
26	TOTAL				$168,519,465		$ 6,369,710,046
27	Expense Lag	Line 23, Col. (E) / (D)		37.80			
28	Revenue Lag	Company Workpapers		35.59			
29	Net Lag	Line 25 - Line 24		(2.21)			
30	RUCO Adjusted Expenses	Col. (C), Line 23		$168,519,465			
31	Cash Working Capital	Line 26 X Line27 / 365 Days		(1,019,458)			
32	Company As Filed	Co. Schedule B-5, Page 1		(2,634,713)			
33	ADJUSTMENT (See MDC-2, Pg 1, L 9)	Line 28 - Line 29		1,615,255			

References:
- Column (A): - Company Schedule B-5, Page 3
- Column (B): RUCO Operating Income Adjustments (See Schedule RLM-7)
- Column (C): Column (B) - (A)
- Column (D): Company Schedule B-5, Page 3
- Column (E): Column (C) X Column (D)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #1 - SERVICE FEES

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	# OF UNITS	FEE	REVENUE
1	ESTABLISHMENT/RE-ESTABLISHMENT	24,862	$30.00	745,860
2	CONNECT/RECONNECT - BUSINESS HOURS	2,190	$30.00	65,700
3	CONNECT/RECONNECT - AFTER BUSINESS HOURS	426	$125.00	53,250
4	ESTABLISHMENT/RE-ESTABLISHMENT - AFTER BUSINESS HOURS	547	$125.00	68,375
5	METER REREAD	62	$20.00	1,240
6	TOTAL REVENUE FROM SERVICE FEES			934,425
7	TEST YEAR REVENUE FROM SERVICE FEES			885,777
8	INCREASE IN REVENUE			$48,648

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #6 - BAD DEBT EXPENSE

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	TEST YEAR RETAIL REVENUES	$153,864,975	UNSE(0783)01732
2	LATE FEES AND MISC SERVICE	813,854	UNSE(0783)01732
3	WEATHER ADJUSTMENT	(410,061)	UNSE(0783)01732
4	CUSTOMER ANNUALIZATION	3,249,883	UNSE(0783)01732
5	CARES DISCOUNT ANNUALIZATION	(52,937)	COMPANY SCH. C-2, PG. 1
6	TOTAL REVENUE	157,465,714	SUM LINES 1 THROUGH 5
7	BAD DEBT EXPENSE RATIO	0.2391%	NOTE (a)
8	ANNUALIZED BAD DEBT EXPENSE	376,500	LINE 6 x LINE 7
9	BAD DEBTS PER COMPANY	579,538	UNSE(0783)01732
10	DECREASE IN BAD DEBT EXPENSE	($203,038)	LINE 8 -LINE 9

NOTE (a)

TEST YEAR BAD DEBT EXPENSE	$356,982
TEST YEAR REVENUE	149,302,474
RATIO	0.2391%

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #7 - FLEET FUEL EXPENSE

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	AVERAGE CONSTRUCTION FTE	109.2	UNSE(0783)02106
2	AVERAGE MILES DRIVEN	14,293	UNSE(0783)02106
3	CONSTRUCTION FTE FOR JULY 2006	114.5	UNSE(0783)02106
4	2006/2007 MILEAGE	1,636,549	LINE 2 x LINE 3
5	MILES PER GALLON	7.63	UNSE(0783)02106
6	GALLONS PURCHASED	214,497	UNSE(0783)02106
7	2007 AVERAGE PRICE PER GALLON	2.77	DR STF 11.24
8	PROFORMA FUEL EXPENSE	594,157	LINE 6 x LINE 7
9	PER COMPANY	647,407	CO. SCH. C-2, PG 3
10	FUEL EXPENSE ADJUSTMENT	($53,250)	LINE 8 - LINE 9

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utility regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Electric, Inc.'s ("UNS" or "Company") application for a permanent rate increase ("Application") for the Company's electric distribution operations in Mohave and Santa Cruz Counties. UNS filed the Application with the ACC on December 15, 2006. The Company has chosen the fiscal year ended June 30, 2006 for the test year in this proceeding.

Q. Briefly describe UNS.

A. UNS is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to the electric distribution operations of UNS, UniSource also provides natural gas distribution service through its other subsidiary UNS Gas, Inc., to customers in Northern Arizona and Santa Cruz County.

...

[1] NYSE ticker symbol UNS.

Q. Please explain your role in RUCO's analysis of UNS' Application.

A. I reviewed UNS' Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNS?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNS entity was the result of that acquisition and the Company's present rates were established in that proceeding. More recently I provided cost of capital testimony in a rate case proceeding that involved UNS Gas, Inc.[2]

...

[2] Docket No. G-04204A-06-0463

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. No. RUCO witnesses Marylee Diaz Cortez, CPA and Rodney L. Moore handled those aspects of the Company's Application.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the current economic climate that UNS is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNS' cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of UNS, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.30 percent cost of equity capital. This 9.30 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending that the Commission adopt the Company-proposed 6.36 percent cost of short-term debt and 8.22 percent cost of long-term debt. This is based on my review of the costs associated with UNS' various debt instruments and credit facilities.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and cost of debt analyses, I am recommending an 8.67 percent cost of capital for UNS. This figure represents the weighted cost of my recommended cost of common equity and my recommended costs of short and long-term debt.

Q. Why do you believe that your recommended 8.67 percent cost of capital is an appropriate rate of return for UNS to earn on its invested capital?

A. The 8.67 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNS, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for UNS?

A. Based on the results of my DCF and CAPM analyses, which ranged from 7.89 percent to 11.56 percent for a sample of electric providers, I am recommending a 9.30 percent cost of equity capital for UNS. My recommended 9.30 percent figure represents an average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate UNS' cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine UNS' cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for UNS, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

...

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

...

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[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

...

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	$1 - [(BV) \div (MP)]$
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation $[(M \div B) + 1] \div 2$.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used $[(M \div B) + 1] \div 2$ as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In the most recent Southwest Gas Corporation rate case[7], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case,

[7] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of eight electric utility companies that have similar operating characteristics to UNS.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of UNS?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNS itself. Although shares of UNS' parent company, UniSource, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of UNS. Consequently it was necessary to create a proxy by analyzing publicly traded electric companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for UNS?

A. All of the electric utility companies in my sample, with the exception of MG Energy Inc., are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility (east, central and west) industry segments. MG Energy Inc. is traded on the NASDAQ[8] which is also a major U.S. stock exchange. Each of the companies in the proxy are engaged in the provision of regulated electric utility services. Attachment A of my testimony contains Value Line's most recent evaluation of the electric utility proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. The eight electric companies included in my proxy (and their NYSE/NASDAQ ticker symbols) are CH Energy Group, Inc. ("CHG"), Cleco Corporation ("CNL"), Hawaiian Electric Industries, Inc. ("HE"), MG

[8] National Association of Securities Dealers Automated Quotation system

Energy Inc. ("MGEE"), Northeast Utilities ("NU"), NSTAR ("NST"), Puget Energy, Inc. ("PSD"), and UIL Holdings ("UIL").

Q. Briefly describe the regions of the U.S. served by the eight electric utilities that make up your sample proxy.

A. The eight electric utilities listed above provide electric and natural gas services to customers in New England (i.e. NU which serves Connecticut, New Hampshire and the western half of Massachusetts; NST which serves the eastern half of Massachusetts including Boston; and UIL which provides electricity to the southern portion of Connecticut), the Middle Atlantic region (i.e. CHG which serves 293,000 customers in the Mid-Hudson Valley region of New York state), the Midwest (i.e. MGEE which provides service to customers in the Madison, Wisconsin area), the South (i.e. CNL which supplies electricity to 267,000 customers in the central part of Louisiana), the Pacific Northwest (i.e. PSD which serves western Washington state), and the Hawaiian islands (i.e. HE which provides electrical service to 434,000 customers on the islands of Oahu, Maui, Molokai, Lanai and Hawaii).

Q. Did the Company's witness also perform a similar analysis using electric utility companies?

A. Yes, the Company's witness, Kentton C. Grant performed a similar analysis of publicly traded electric utility companies.

Q. Does your sample of electric utilities include all of the same companies that Mr. Grant included in his sample?

A. Yes. My sample includes the same eight electric utility companies that Mr. Grant included in his sample.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2002 to 2006. Schedule WAR-5 also includes Value Line's projected 2007, 2008 and 2010-12 values for the retention ratio, return on book equity, book value per share growth rate, and number of shares outstanding for the electric utility companies in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Hawaiian Electric Industries, Inc., (NYSE symbol HE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10 of my testimony) to multiply HE's earned return on common equity by its earnings retention ratio for each year in the 2002 to 2006 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, HE's sustainable internal growth rate ranged from 2.65 percent in 2002 to 0.67 percent in 2006. The company's growth rates experienced a declining pattern during the majority of the observation period, which resulted in a 1.58 percent average over the 2002 to 2006 time frame. Value Line's analysts are forecasting a further decline through 2007 before the trend reverses itself and growth increases to a level of 3.50 percent during the 2010-12 period. Value Line believes that earnings will increase by 4.00 percent but dividend growth will remain flat. Value Line has also decreased its book value growth projection downward from 2.50 percent to 0.50 percent. Based on the aforementioned projections, I believe that a 3.35 percent rate of internal sustainable growth is reasonable for HE.

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that HE's share growth averaged 2.56 percent over the 2002 - 2006 observation period. However, Value Line expects future outstanding shares to increase modestly from 83.50 million in 2006 to 87.00 million by the end of 2012. Taking this data into consideration, I am estimating a 2.00 percent rate of share growth for HE. My final dividend growth rate estimate for HE is 4.22 percent (3.35 percent internal + 0.87 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 3.94 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. As can be seen in Schedule WAR-6, my 3.94 percent estimate is 74 basis points higher than the 3.20 percent average of Value Line's and Zacks Investment Research's ("Zacks") projected and historic averages of earnings per share, dividends per share and book value per share. My 3.94 percent estimate is also 238 basis points higher than Value Line's 1.56 percent 5-year historic compound history. Both the Value Line and Zacks earnings projections (Attachment B) indicate that investors are expecting increased performance from electric utility companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 3.94 percent estimate is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's most recent (i.e. March 30, May 11, and June 1, 2006) Ratings and Reports for the Electric Utility (Central, West and East) Industry updates. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period April 16, 2007 to June 8, 2007.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 7.89 percent.

...

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[9], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[10] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities),

[9] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[10] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

where:	k	=	cost of capital of a given security,
	r_f	=	risk-free rate of return,
	ß	=	beta coefficient, a statistical measurement of a security's systematic risk,
	r_m	=	average market return (e.g. S&P 500), and
	$r_m - r_f$	=	market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[11] This resulted in a risk-free (r_f) rate of return of 5.05 percent.

[11] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from May 4, 2007 to June 8, 2007.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of the historical yields of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[12] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument).

[12] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2006 as the proxy for the market rate of return (r_m). The information was obtained from Morningstar's <u>SBBI Yearbook</u>, which publishes historical data on stock returns, U.S. Treasury yields and rates of inflation. The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 5.55 percent (10.40% - 4.85% = <u>5.55%</u>). The risk premium that results by using the arithmetic mean calculation for r_m is 7.45 percent (12.30% - 4.85% = <u>7.45%</u>).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the electric utilities used in my proxy, were calculated by Value Line and were published in the most recent updates (i.e. March 30, May 11, and June 1, 2007) for the Central, West and East regional electric providers in my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.75 to 1.30 with an average beta of 0.90.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 9.85 percent. My calculation using an arithmetic mean results in an average expected return of 11.56 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	7.89%
CAPM	9.85% – 11.56%

Based on these results, my best estimate of an appropriate range for a cost of common equity for UNS is 7.89 percent to 11.56 percent. My final recommendation for UNS is 9.30 percent.

Q How did you arrive at your recommended 9.30 percent cost of common equity?

A. My recommended 9.30 percent cost of common equity is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.80 percent cost of equity capital proposed by the Company is 250 basis points higher than the 9.30 percent cost of equity capital that I am recommending.

...

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board

("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[13] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve

[13] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of

2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding the recession that the U.S. now appears to have recovered from.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates, moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001, a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[14]"

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

...

[14] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to its current level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What has been the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the existing federal funds rate of 5.25 percent, where it has stood since June 29, 2006.

. . .

Q. How have analysts viewed the Fed's actions over the last five years?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[15] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[16]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings, like the one that the Fed managed to pull off during the 1994 – 1995 time frame, in which a recession or a bear market were avoided rarely happen[17]. Since it began increasing the federal funds rate in June 2004, the Fed has assured investors that it would increase rates at a "measured" pace. Many analysts

[15] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[16] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[17] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[18]. According to Mr. Browning, the hope, at the time that his article was published, was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Has the Fed's attempt to engineer a soft landing been successful to date?

A. It would appear so. Articles published in the mainstream financial press have been generally upbeat on the current economy. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[19]

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[18] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

[19] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2001 affected benchmark rates?

A. Despite the increases by the FOMC, interest rates and yields on U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, with the exception of the federal discount rate (the rate charged to member banks), which has increased to 6.25 percent from 5.73 percent in 2000, the other key interest rates (i.e. the prime rate and the federal funds rate) are still below their year-end 2000 levels.

Q. What has been the trend in other leading interest rates over the last year?

A. As of June 8, 2007, the leading interest rates are showing mixed results. The prime rate has increased from 8.00 percent a year ago to its current level of 8.25 percent. The benchmark federal funds rate, just discussed, has increased from 5.00 percent, in June 2006, to its current level of 5.25 percent (the result of the seventeen quarter point increases noted earlier). The yields on several maturities of U.S. Treasury instruments have increased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[20], in which long-term rates fell as short-term rates increased, thus creating the somewhat inverted yield curve that existed as of June 8, 2007 (Attachment C), appears to have

[20] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

ended and a more traditional yield curve (where yields increase as maturity dates lengthen) appears to be forming. The 91-day T-bill rate, used in my CAPM analysis, has increased slightly from 4.82 percent, in June 2006, to 4.83 percent as of June 8, 2007. The 1-Year Treasury constant maturity rate also decreased from 5.07 percent over the past year to 4.96 percent. Again, for the most part, these current yields are lower than corresponding yields that existed during the early nineties (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. On May 9, 2007, the Federal Reserve decided not to increase or decrease the federal funds rate for the seventh straight FOMC meeting and left the key rate unchanged at 5.25 percent. According to an article[21] that appeared in the May 10, 2007 online edition of The Wall Street Journal, the Fed's action was based on some recent weakening of the economy. According to the Fed's statement that was released after the decision was made to sit pat on rates, the members of the FOMC believed that moderate economic growth was the likeliest scenario in the coming months. The statement also noted that the members of the FOMC expected somewhat elevated core inflation rates, which exclude volatile food and energy prices, to come down. The article also stated that the

[21] Ip, Greg, "Inflation Risk Keeps Fed on Alert," The Wall Street Journal, May 10, 2007.

financial markets still expect a rate cut later this year. In another article[22] that appeared at the time of this writing, The Wall Street Journal's Brian Blackstone quoted Chairman Bernanke as saying that "despite an 'ongoing' drag from the housing sector, the U.S. economy should expand at a moderate pace near its underlying potential in coming months as other factors limiting growth reverse." Chairman Bernanke also alluded, in prepared remarks to be delivered to the International Monetary Conference in Cape Town South Africa, to recent favorable readings on core inflation, citing the "gradual ebbing" that has been seen. Mr. Blackstone also noted that "amid signs of economic recovery and a deceleration in inflation, the Fed is expected to keep the key federal-funds rate at 5.25 percent throughout much of 2007 and perhaps even into 2008."

The recent views of Value Line analysts, who anticipate lower rates of inflation in the coming months, support the aforementioned outlook for stable rates. In their Economic and Stock Market Commentary that appeared in the February 2, 2007 edition of Value Line's Selection and Opinion publication, Value Line's analyst's stated the following:

> "Inflation is likely to start trending lower over the next few quarters, in part because the modest rate of GDP growth should cap the the increases in demand for labor and raw materials. Moreover, recent declines in oil prices will keep costs down for products that are oil-based and for companies that are heavy users of electricity."

[22] Blackstone, Brian, "Bernanke Sees Moderate Growth Despite Continued Housing Drag," The Wall Street Journal, June 5, 2007.

On March 23, 2007 Value Line's analysts had this to say:

> "Housing remains one of the wild cards in the economic situation. Recent months have seen this market weaken further, as slumping demand and higher monthly payments (for those with mortgages where the rates are now rising) have forced prices downward in a number of regions of the country. Should the recent gains in personal income and the brighter employment outlook help to gradually lessen the housing pressures, as we suspect, this sector should see its long decline moderate in the next few quarters.

Value Line's analysts stated the following in the June 8, 2007 Selection & Opinion publication:

> "It may be touch and go as to whether or not the Federal Reserve will reduce interest rates in the months to come. We think the Fed will carefully weigh the latest data from the housing and industrial fronts to gauge whether the economy can move forward, at even 2.0% - 2.5%, in the absence of lower interest rates. Should the Fed conclude that a rate reduction is needed, it may then try to determine whether or not inflation is low enough to justify such a cut. We think the Fed will end up voting for one to three rate reductions over the next year or so, on the expectation that inflation will slow modestly.

Q. How has the current economic environment of lower interest rates affected the electric utility industry as a whole?

A. Value Line analyst Nils C. Van Liew took note of the current environment of low interest rates recently. In Value Line's Electric Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> "Several factors are, no doubt, driving the electric utilities' strong share - price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost-effectively build new power plants and maintain existing ones.) 'Cheap money' also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low, though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns."

Q. What are the current dividend yields of electric utility stocks followed by Value Line?

A. In the May 11, 2007 Electric Utility (West) Industry update, Value Line analyst Paul E. Debbas, CFA, observed that following the continuing rise in electric utility stock prices (which have 52-week - or even all-time highs – as of late), the average yield of the electric utility stocks followed by Value Line has fallen to a historically low 3.20 percent. Mr. Debbas went on to note that by contrast, the average yield on electric stocks was over 5.00 percent as recently as 1999. According to Mr. Debbas, electric utility stocks hold a lot of appeal to investors seeking dividend income when returns on cash are very low. He also made note of the fact that the demand for electric utility stocks increased as a result of the 2003 change in the treatment of dividends.

Mr. Debbas' remarks were echoed by Value Line analyst Arthur H. Medalie. In his March 30, 2007 update on the Electric Utility (Central) Industry, Mr. Medalie stated that the average dividend yield for the electric utility industry is about double that of all dividend-paying stocks followed by Value Line. Mr. Medalie opined that conservative investors might want to consider electric utility companies, engaged in basic utility operations, which have strong finances and reasonable dividend growth prospects as an investment opportunity.

...

Q. How does the 3.20 percent average yield on electric utility stocks noted above compare with the average dividend yield of your sample electric utility companies?

A. As can be seen in Schedule WAR-3, my sample electric utility companies have an average dividend yield of 3.95 percent which is 75 basis points higher than the 3.20 percent average yield on electric utility stocks reported by Value Line's Mr. Debbas.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.30 percent cost of equity capital that you have estimated is reasonable for UNS?

A. I believe that my recommended 9.30 percent cost of equity will provide UNS with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards), a rebound in growth in new housing construction (attributed to historically low interest rates), and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNS' testimony on the Company-proposed costs of long and short-term debt?

A. Yes, I have reviewed the testimony prepared by Mr. Grant.

Q. Do you agree with Mr. Grant's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of long-term debt figure of 8.22 percent?

A. Yes. I should also note that the financing application (Docket No. E-04204A-06-0493) referenced in Company witness Grant's direct testimony was approved by the Commission in Decision No. 69395, dated March 22, 2007.

Q. What are your recommended costs of long and short-term debt?

A. I am recommending the Company-proposed cost of long-tem debt of 8.22 percent and the Company-proposed cost of short-term debt of 6.36 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNS' testimony regarding the Company's proposed capital structure?

A. Yes, I have reviewed the direct testimony of Company witness Grant, who testified on UNS' proposed capital structure.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity.

Q. What capital structure are you proposing for UNS?

A. I am recommending the same capital structure being proposed by UNS.

Q. Is the capital structure proposed by UNS in line with industry averages?

A. Yes. As can be seen in Schedule WAR-9, the capital structure proposed by UNS is just slightly higher in equity than the average capital structure of the electric utility companies included in my sample.

Q. In terms of risk, how does your recommended capital structure compare to the electric utility companies in your sample?

A. The electric utility companies in my sample would be considered as having a slightly higher level of financial risk (i.e. the risk associated with debt repayment) because of their slightly higher levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived in my DCF analysis is applicable to companies that are slightly more leveraged and, theoretically speaking, slightly more risky than a utility with a level of debt similar to UNS'. In the case of a publicly traded company, such as those included in my proxy, a company with UNS' level of debt would be perceived as having a slightly lower level of financial risk and would therefore also have a slightly lower expected return on common equity. Based on the aforementioned facts I have decided not to make any upward or downward adjustments to my recommended cost of equity capital for UNS.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 9.89 percent. This composite figure is the result of a weighted average of UNS' proposed 6.36 percent cost of short-term debt, 8.22 percent cost of long-term debt and 11.80 percent cost of common equity. The Company-proposed 9.89 percent weighted cost of capital is 122 basis points higher than the 8.67 percent weighted cost that I am recommending, which is the weighted cost of my recommended 6.36 percent cost of short-term debt, 8.22 percent cost of long-term debt and 9.30 percent cost of common equity.

COMMENTS ON UNS' COST OF EQUITY CAPITAL TESTIMONY

Q. Have you studied the methodology that Company witness Grant used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Mr. Grant use to arrive at his cost of common equity for UNS?

A. Mr. Grant used a DCF methodology and a CAPM methodology to estimate UNS' cost of common equity.

Q. Can you provide a comparison of the results derived from Mr. Grant's models and yours?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Mr. Grant conducted his?

A. Yes, Mr. Grant relied on the results of a multi-stage DCF model, using the proxy of eight electric utility companies that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on.

Q. Do you agree with Mr. Grant's rationale for not relying on the single-stage DCF model?

A. 'No. The long-term growth rate that Mr. Grant uses in the second stage of his multi-stage DCF model is a 6.50 percent figure that falls within a range bounded on the upper side by investor expectations of the electric utility industry as a whole (which also falls within the range of analysts growth projections of his sample companies), and on the lower side by a 6.00 percent long-term projection of inflation-adjusted GDP, which is an inflation adjusted-projection of the growth rate of the entire U.S. economy. The use of such a growth estimate assumes that the long-term growth rate for the electric-utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S. A good argument can be made that more emphasis should be placed on the near term component of Mr. Grant's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Mr. Grant?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration long-term growth rate projections that are specific to the electric utilities included in my proxy.

Q. What is the difference between Mr. Grant's DCF estimate and your DCF estimate?

A. Mr. Grant's 10.35 percent median DCF estimate, derived from his multi-stage model, is 246 basis points higher than 7.89 percent cost of common equity derived from my constant growth, or single-stage DCF model which is a mean average of the estimates of the eight electric utility companies in my proxy.

Q. Does Mr. Grant provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits contained in his testimony contain inputs and estimates used in his multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Mr. Grant's exhibits, a single-stage model would produce a cost of common equity estimate of 7.92 percent which is just 3 basis points higher than my DCF estimate of 7.89 percent.

Q. Have there been any changes in closing stock prices since Mr. Grant filed his direct testimony?

A. Yes. As Value Line's analysts noted in their recent updates on the electric utility industry, stock prices for electric utilities have been on the rise. The stock prices for the electric utility companies used in our proxies have increased since Mr. Grant filed his direct testimony, thus producing lower dividend yields. The difference between the average closing stock prices used in my analysis and Mr. Grant's analysis are as follows:

	Rigsby	Grant	Difference
CHG	$47.83	$49.73	- $1.90
CNL	$27.75	$25.14	$2.16
HE	$25.40	$27.10	- $1.70
MGEE	$35.39	$32.99	$2.40
NU	$31.84	$23.09	$8.75
NST	$35.95	$32.82	$3.13
PSD	$25.83	$22.44	$3.39
UIL	$34.31	$37.13	- $2.82

The differences in our respective dividend yields are as follows:

	Rigsby	Grant	Difference
CHG	4.52%	4.35%	0.49%
CNL	3.24%	3.58%	- 0.34%
HE	4.88%	4.58%	0.30%
MGEE	3.93%	4.28%	- 0.35%
NU	2.51%	3.30%	- 0.79%
NST	3.62%	3.87%	- 0.25%
PSD	3.87%	4.46%	- 0.59%
UIL	5.04%	4.66%	0.38%

When Mr. Grant's first year dividend estimates (i.e. the D_1 component of the DCF model) are divided by my more recent closing stock prices (i.e. the P_0 component of the DCF model) the resulting average dividend yield is 3.97 percent, which is only slightly higher than my 3.95 percent result exhibited in schedule WAR-3. The addition of a mean average of Mr. Grant's lower 5-year growth (i.e. the "g" component of the DCF model) estimate of 3.73 percent for his sample electric utility companies produces a single-stage estimate of 7.70 percent, which is 19 basis points lower than my 7.89 percent single-stage model estimate.

Based on this information it is fair to say that a single stage model using updated stock prices, while holding Mr. Grant's other DCF component estimates constant, would produce a lower single-stage DCF estimate than the one that I have calculated.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Mr. Grant conducted his?

A. The main difference between Mr. Grant's CAPM analysis and mine is that he relied solely on an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2005 as the proxy for the market rate of return (i.e. r_m) in order to arrive at his market risk premium (i.e. $r_m - r_f$) in his CAPM model.

Q. What financial instrument did Mr. Grant use as a proxy for the risk free (i.e. r_f) rate in his CAPM model?

A. Mr. Grant used the yield to maturity on a 20-year U.S. Treasury bond, which was 4.84 percent as of September 29, 2006.

Q. What is the current yield on a 20-year U.S. Treasury bond?

A. As of June 8, 2007 the yield on a 20-year U.S. Treasury bond had increased to 5.21 percent.

Q. Did Mr. Grant use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However the average of Value Line's beta's for the electric utility companies in our samples proxies have increased since Mr. Grant filed his direct testimony. The mean average of the Value Line betas used by Mr. Grant is 0.86 as opposed to my average beta of 0.90.

Q. What would Mr. Grant's expected return be if his CAPM model (using an arithmetic mean) were updated to include the aforementioned changes in the average beta coefficient and the 20-year Treasury bond yield?

A. An update of Mr. Grant's CAPM model using an average beta of 0.90 and a risk free rate of 5.21 percent would produce an expected return of 11.60 percent, which is 4 basis points higher than my 11.56 percent result using an arithmetic mean.

Q. What is the difference between Mr. Grant's CAPM estimates and your CAPM estimates?

A. Mr. Grant's 10.70 percent median CAPM estimate using an arithmetic mean for the market risk premium (including Cleco Corporation) is 86 basis points lower than the 11.56 percent cost of common equity derived from my arithmetic mean CAPM analysis which is a mean average of the eight electric utility companies in my proxy. Mr. Grant's CAPM 10.70 percent median is 85 basis points higher than the 9.85 percent cost of common equity derived from my geometric mean CAPM analysis. In making his recommended high and low end ranges, displayed on page 19 of his direct testimony, Mr. Grant excluded the results of Cleco Corporation because of its higher beta coefficient that equaled 1.25 at the time of his study and 1.30 at the time of my study (the exclusion of Cleco Corporation results in a median of 10.50 percent).

Final Cost of Equity Estimate

Q. How did Mr. Grant arrive at his final estimate of 11.80 percent for UNS?

A. Mr. Grant's final 11.80 percent recommendation is the 11.20 percent high end of his range of DCF and CAPM estimates plus an upward adjustment of 60 basis points. The 60 basis point upward adjustment is Mr. Grant's observed difference between utility bond yields with investment grade Triple-B credit ratings (Baa or BBB) and speculative Double-B credit ratings (Ba or BB). Mr. Grant's upward adjustment of 60 basis points is based on his belief that UNS is riskier as a result of a number of factors including the Company's size, a speculative-grade credit rating associated with long-term notes issued in 2003, high customer growth rate, and the need to procure a new power supply in 2008.

Q. Do you believe that UNS should be awarded a higher return on equity based on the factors cited by Mr. Grant?

A. No. The Commission in prior cases has rejected many of the factors cited by Mr. Grant. This includes such issues such as company size and customer growth projections. In regard to UNS' need to procure a new power supply in 2008, RUCO witness Marylee Diaz Cortez, CPA, is recommending modifications to the Company's purchased power and fuel adjustor mechanism that will, if adopted by the Commission, mitigate the risks associated with this future event and improve UNS' overall financial condition.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Grant or any other witness for UNS constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNS?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:	University of Phoenix Master of Business Administration, Emphasis in Accounting, 1993
	Arizona State University College of Business Bachelor of Science, Finance, 1990
	Mesa Community College Associate of Applied Science, Banking and Finance, 1986
	Society of Utility and Regulatory Financial Analysts 38th Annual Financial Forum and CRRA Examination Georgetown University Conference Center, Washington D.C. Awarded the Certified Rate of Return Analyst designation after successfully completing SURFA's CRRA examination.
	Michigan State University Institute of Public Utilities N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999
	Florida State University Center for Professional Development & Public Service N.A.R.U.C. Annual Western Utility Rate School, 1996
EXPERIENCE:	Public Utilities Analyst V Residential Utility Consumer Office Phoenix, Arizona April 2001 – Present
	Senior Rate Analyst Accounting & Rates - Financial Analysis Unit Arizona Corporation Commission, Utilities Division Phoenix, Arizona July 1999 – April 2001
	Senior Rate Analyst Residential Utility Consumer Office Phoenix, Arizona December 1997 – July 1999
	Utilities Auditor II and III Accounting & Rates – Revenue Requirements Analysis Unit Arizona Corporation Commission, Utilities Division Phoenix, Arizona October 1994 – November 1997
	Tax Examiner Technician I / Revenue Auditor II Arizona Department of Revenue Transaction Privilege / Corporate Income Tax Audit Units Phoenix, Arizona July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0403	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase

ATTACHMENT A

INDUSTRY TIMELINESS: 71 (of 96)

All of the major utilities in the central United States are reviewed in this Issue. Those serving the western region may be found in Issue 11. The eastern companies are covered in Issue 1.

The pressure of an ever-growing demand for energy is reducing reserve margins and leading to the need for more generation. Power usage in the U.S. is increasing at an annual rate of 2%. This, coupled with low interest rates, is inducing utilities to increase spending on new plants. Construction of fossil-fueled facilities accounts for most of the new capacity. But dependence on foreign oil, atmospheric pollution created by coal-fired units, and the high cost of natural gas have stimulated interest in renewable energy by state and federal regulatory bodies and by utilities themselves.

Regulatory Requirements

At the turn of the century, wind, geothermal, solar, biomass, and miscellaneous renewables accounted for only a low single-digit percentage of power output. A turnaround began as state and federal officials and company managements came to realize their benefits. Jeff Bingaman, chairman of the Senate Energy and Natural Resources Committee, recently announced that he will introduce a bill requiring that 15% of the nation's power supply come from renewable sources by 2020. On the state level, the Arizona commission requires renewables in its jurisdiction to represent 15% of total power output by 2025. Legislators in Wisconsin have introduced a more modest bill calling for 10% from renewables by 2015. In Michigan, however, a bill providing for 10% of power from renewable sources and granting tax credits for wind turbines and windmills was vetoed by the governor, on the grounds that the state could not afford to grant tax credits because of the loss of jobs in the automotive industry. At this time, renewable portfolio requirements are in place in 20 states.

A New Fuel Emerges

In 2006, Edison International led the nation in delivery of energy from geothermal, wind, biomass, and solar power. It generated sufficient electricity from this program to serve 1.8 million homes for an entire year. It hopes to have long-term contracts with companies developing these projects to furnish 20% or more of its customer needs by 2010. PG&E, for its part, has agreed to buy 500 megawatts (mw) of solar power, 300 mw of wind-driven energy, and lesser amounts of biomass and geothermal generation. With these purchases, renewables will account for 20% of the company's output in the next few years. FPL Group is not far behind. It invested $1 billion last year in wind-driven power in 15 states, helped by federal tax credits of 1.8¢ a kilowatt-hour that make this source competitive with fossil-fuel generation. The credits, which were due to expire at the end of 2007, were extended for an additional year, and all wind mills already operating at that time will continue to benefit from tax credits when the law elapses. FPL Group also has a 310-mw investment in solar power, but has no plans to expand in this area because of the absence of tax credits. In the central region, *TXU* plans to boost its wind power capacity to 1,500 mw, making it the largest source of this power in the country. *Western Resources* has issued a request for 500 mw of wind and other renewable sources of energy, which it will either lease or buy outright. *Alliant Energy* has purchased development rights to a proposed 80- to 100-mw wind farm. It is also studying the burning of paper byproducts, agricultural waste, and animal and food waste. *Entergy* has issued a request for proposals for 40,000 megawatt hours of renewable energy to be used as a pilot to help determine interest in acquiring alternative power sources.

A report by consulting firm Wood Mackenzie stated that if renewables accounted for 15% of national power output, natural gas and wholesale power costs would be driven down. Over the next 20 years, that could lead to savings of as much as $240 billion, more than outweighing the high capital cost of building renewable capacity. Though the addition of renewables would not reduce greenhouse emissions below present levels, it would slow their growth. Despite these pluses, challenges remain to renewable power projects, because of uncertainty about tax incentives and concerns related to siting of new facilities.

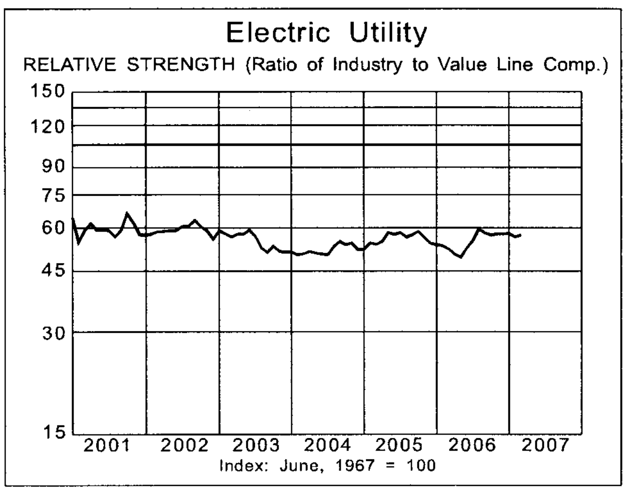
Investment Advice

The Electric Utility Industry is untimely, but it may be of interest because its average dividend yield is about double that of all dividend-paying stocks followed by *Value Line*. Conservative investors might consider those companies with strong finances, reasonable dividend-growth prospects, and those engaged in basic utility operations.

Arthur H. Medalie

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
289.2	299.3	336.7	354.1	***380***	***400***	Revenues ($bill)	***480***
19.3	20.3	24.0	25.7	***29.0***	***32.0***	Net Profit ($bill)	***39.0***
30.3%	30.3%	29.5%	29.7%	***33.5%***	***34.5%***	Income Tax Rate	***34.5%***
4.3%	3.5%	3.5%	3.3%	***4.0%***	***4.0%***	AFUDC % to Net Profit	***3.0%***
59.1%	57.2%	55.7%	55.0%	***52.5%***	***52.0%***	Long-Term Debt Ratio	***49.5%***
39.2%	41.7%	43.1%	43.9%	***46.5%***	***47.0%***	Common Equity Ratio	***49.5%***
439.5	441.8	446.1	473.9	***510***	***520***	Total Capital ($bill)	***560***
443.9	453.6	469.3	496.6	***535***	***560***	Net Plant ($bill)	***600***
6.4%	6.5%	7.2%	7.3%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.0%***
10.7%	10.8%	12.1%	12.2%	***11.0%***	***11.0%***	Return on Shr. Equity	***11.0%***
10.9%	10.9%	12.3%	12.4%	***11.0%***	***11.0%***	Return on Com Equity	***11.0%***
4.8%	4.7%	5.5%	5.5%	***5.0%***	***5.0%***	Retained to Com Eq	***5.0%***
57%	57%	56%	56%	***63%***	***61%***	All Div'ds to Net Prof	***59%***
15.2	16.0	15.8	15.9	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.5***
.80	.85	.85	.86			Relative P/E Ratio	***.90***
3.7%	3.5%	3.5%	3.5%			Avg Ann'l Div'd Yield	***4.4%***



All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

Since some parts of the country are facing a shortage of generating capacity in the coming years, some utilities have reentered the construction cycle. We examine the advantages and disadvantages of each kind of generation.

Electric utility stocks performed well in 2006, and the momentum has continued into 2007. The average yield is at a historical low.

Building Generating Capacity

A few years ago, many parts of the country were awash in generating capacity after numerous plants (virtually all of them gas-fired) were built in the late 1990s and early 2000s. Most of these facilities were built by independent power producers (IPPs) or nonregulated siblings of electric utilities. After the collapse of the power markets in 2001 and 2002, along with the spike in natural gas prices, some IPPs filed for bankruptcy protection, and little capacity was built. Some plants were even discontinued after construction had begun.

Since a few years have passed with an increase in demand for electricity but without much new generating capacity, some utilities are concerned about a looming power shortage. So, they have begun to build power plants or have facilities on the drawing board. Some also want to build capacity in order to reduce their dependency on purchased power, the cost of which has become very volatile at times. (*Puget Energy* and *Sierra Pacific Resources* are two such companies.) This raises the question: What kind of plants should be built?

Gas-fired plants are easier and less costly to build than coal-fired facilities, and are also cleaner, but the price of natural gas is volatile and supplies in North America are becoming tighter. (There is actually plenty of gas, but much of it is off-limits to developers due to environmental concerns.) Coal is abundant, but comes with environmental issues. Some utilities are studying the possibility of building nuclear plants. Nuclear facilities do not produce any greenhouse gases, but they are very expensive and difficult to build. Moreover, a permanent repository for nuclear waste has not yet been

INDUSTRY TIMELINESS: 80 (of 96)

established. Even if the regulatory process toward building a nuclear unit were to begin today, the plant wouldn't come on line before the middle of the next decade. Wind power is appealing to a lot of utilities, especially because 23 states require that a certain proportion of power come from renewable sources by a specified year. But the capital costs of building wind projects are high, the facilities are typically built in remote areas that require a lot of transmission spending, and wind power isn't economically viable without production tax credits.

There are many examples of the varied approaches that utilities are taking to add capacity. TXU backed off its plans to build coal-fired plants after much criticism, so the company is now considering nuclear power. Wisconsin Energy is building two coal-fired units and two gas-fired units (one of which is already on line.) The plants will be owned by a nonregulated subsidiary, which will lease them to its utility sibling. In recent years, *Puget Energy's* utility subsidiary has built two wind projects and acquired two gas-fired plants. *Sierra Pacific Resources'* two utilities have built or acquired gas-fired plants and have a big coal project planned. Some utilities in Missouri have begun construction of a coal-fired unit. Another group is also studying coal gasification plants, notably American Electric Power, Duke Energy, Southern Company, and TECO Energy. These plants are very expensive, however.

Investment Advice

Following the continuing rise in most electric utility stocks, the average yield of the group has fallen to a historically low 3.2%. (By contrast, it was over 5% as recently as 1999.) These stocks hold a lot of appeal to investors seeking dividend income when returns on cash are very low. The 2003 change in the tax treatment of dividends has stimulated the demand for these equities. Dividend growth (and, in the case of CMS Energy, a dividend restoration) has been another selling point of electric utility issues. Many of these stocks have reached 52-week highs—or even all-time highs—of late. We are concerned about the lofty valuation of these equities and thus advise investors to proceed cautiously.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2003	2004	2005	2006	2007	2008		10-12
289.2	299.3	336.7	336.0	**380**	**400**	Revenues ($bill)	**480**
19.3	20.3	24.0	26.8	**29.0**	**32.0**	Net Profit ($bill)	**39.0**
30.3%	30.3%	29.5%	32.0%	**33.5%**	**34.5%**	Income Tax Rate	**34.5%**
4.3%	3.5%	3.5%	4.1%	**4.0%**	**5.0%**	AFUDC % to Net Profit	**3.0%**
59.1%	57.2%	55.7%	53.3%	**52.5%**	**52.0%**	Long-Term Debt Ratio	**49.5%**
39.2%	41.7%	43.1%	45.5%	**46.5%**	**47.0%**	Common Equity Ratio	**49.5%**
439.5	441.8	446.1	448.7	**510**	**520**	Total Capital ($bill)	**560**
443.9	453.6	469.3	481.0	**535**	**560**	Net Plant ($bill)	**600**
6.4%	6.5%	7.2%	7.7%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.7%	10.8%	12.1%	12.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.0%**
10.9%	10.9%	12.3%	13.0%	**11.0%**	**11.0%**	Return on Com Equity	**11.0%**
4.8%	4.7%	5.5%	6.2%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
57%	57%	56%	53%	**63%**	**61%**	All Div'ds to Net Prof	**59%**
13.5	15.2	16.0	15.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
.77	.80	.85	.82			Relative P/E Ratio	**.90**
4.1%	3.7%	3.5%	3.5%			Avg Ann'l Div'd Yield	**4.4%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2003	2004	2005
% Change Retail Sales (kwh)	+1.3	+.3	+5.4
Average Indust. Use (mwh)	1662	1384	1497
Avg. Indust. Revs. per kwh (¢)	5.07	5.25	5.78
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.9	+1.6	+1.2
Fixed Charge Coverage (%)	207	230	260

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western companies are covered in Issue 11.

As measured by share-price performance, investor sentiment towards the electric utilities, including those serving the eastern seaboard, remains high. During the three-month stretch since our last review, a majority of the group (19 of 22) has boasted share-price gains, with 11 besting the 5% advance by the S&P 500 Index. *Central Vermont Public Service* tops the list (+40%). Recent merger activity in northern New England has fueled speculation that the tiny Rutland, VT-based utility (market capitalization: $375 million) is a buyout candidate. By contrast, *UIL Holdings*, parent of Connecticut-based utility United Illuminating, was the laggard of the group. Its shares are down 15%.

Rich Valuations

The valuations with which electric utilities are currently being accorded are increasingly a topic for discussion. We still think that there is some "frothiness" in the sector and that, in general, investors can expect fairly muted total returns (capital appreciation, plus dividends) out to 2010-2012.

Price-to-earnings multiples certainly suggest that many of the names here are richly valued. Half of the eastern utility group's shares are trading at a 20%-plus premium to their median price-to-earnings ratio. The (price-to-earnings) discount at which the group typically trades, relative to the *Value Line Composite Index*, has also narrowed substantially. That said,we are not dismissing the idea that a more-benign regulatory environment may result in higher sustainable earnings growth and that utilities, therefore, deserve more-positive valuations.

Transmission Corridors

The proposed establishment of national interest electric transmission corridors (NIETCs), including one covering parts of six Mid-Atlantic States (NY, NJ, MD, VA, WVA, PA) and the District of Columbia, is being hotly debated. Should the Department of Energy sign off on the designation of these corridors, the Federal Energy Regulatory Commission will have increased power to ease the often languid state and local approval process for new interstate transmission investment.

INDUSTRY TIMELINESS: 65 (of 96)

Economic incentives, including fairly attractive returns on equity rates, have already spurred tranmission investment. The establishment of these corridors should be another log on the proverbial fire. As mandated by the Energy Policy Act of 2005, these initiatives and others will help improve reliability of the nation's power grid. It is also argued that the corridors will promote the development of renewable energy sources, since these long-range conduits can connect typically rural wind farms and high-energy-demand population centers.

New power transmission projects could ultimately boost the earnings of regional service providers. Utilities with large-scale transmission proposals include *Allegheny Energy*, *American Electric Power*, *Dominion Resources*, and *PEPCO Holdings*. That said, there is pretty fierce opposition to these NIETCs, not the least of which is the contention that they usurp states' rights.

Nuclear Power

Constellation Energy, *Central Vermont Public Service*, and other utilities that rely heavily on nuclear power for their power output have been standouts of late, in terms of share-price performance. That is not very surprising. More and more, nuclear power is being touted as low cost, low emission, and, "energy independence" enabling. On the downside, nuclear reactors are high profile targets for terrorists. What to do with spent fuel remains a question as well.

Investment Considerations

Among the positive attributes that investors should look for when seeking an attractive utility are an economically healthy local service territory (such as those in the Southeast); a large customer base; good management-regulator relations; access to low-cost power generation (coal, nuclear); and ample fixed-charge coverage.

Nils C. Van Liew

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
311.7	321.8	353.4	347.7	**375**	**390**	Revenues ($bill)	**470**
20.2	21.7	25.6	27.5	**32.0**	**34.0**	Net Profit ($bill)	**40.0**
30.7%	30.4%	29.6%	32.1%	**33.0%**	**33.0%**	Income Tax Rate	**33.0%**
4.8%	3.7%	3.5%	4.1%	**4.0%**	**4.0%**	AFUDC % to Net Profit	**3.0%**
59.1%	56.7%	55.1%	53.4%	**52.0%**	**51.5%**	Long-Term Debt Ratio	**49.5%**
39.3%	42.2%	43.8%	46.6%	**47.0%**	**47.5%**	Common Equity Ratio	**49.5%**
474.0	475.3	477.1	462.6	**480**	**500**	Total Capital ($bill)	**560**
478.9	487.1	498.5	449.6	**470**	**490**	Net Plant ($bill)	**550**
6.2%	6.5%	7.2%	7.7%	**8.0%**	**8.0%**	Return on Total Cap'l	**7.0%**
10.4%	10.5%	12.0%	12.7%	**14.0%**	**14.0%**	Return on Shr. Equity	**13.5%**
10.5%	10.6%	12.1%	12.9%	**14.2%**	**14.2%**	Return on Com Equity	**13.5%**
4.4%	4.5%	5.3%	6.2%	**6.0%**	**6.0%**	Retained to Com Eq	**5.0%**
60%	59%	57%	57%	**57%**	**57%**	All Div'ds to Net Prof	**59%**
13.8	15.3	16.0	15.3	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.79	.81	.85	.83	*Value Line*		Relative P/E Ratio	**.90**
4.3%	3.8%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	**4.4%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2003	2004	2005
% Change Retail Sales (kwh)	+1.3	+.3	+5.4
Average Indust. Use (mwh)	1662	1384	1497
Avg. Indust. Revs. per kwh (¢)	5.07	5.25	5.78
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.9	+1.6	+1.2
Fixed Charge Coverage (%)	207	230	260

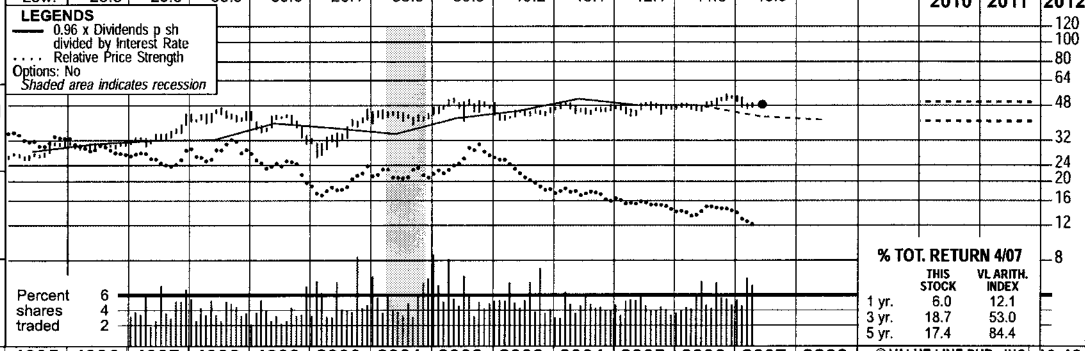
Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

CH ENERGY GROUP NYSE-CHG

RECENT PRICE **48.55** | P/E RATIO **18.0** (Trailing: 17.5; Median: 15.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS 4 Lowered 3/23/07
SAFETY 1 Raised 12/7/01
TECHNICAL 4 Raised 6/1/07
BETA .85 (1.00 = Market)

High:	31.5	43.9	47.1	45.0	46.3	45.9	52.4	49.7	49.6	50.2	54.9	53.8
Low:	28.8	29.8	38.9	30.6	26.1	38.3	39.9	40.2	43.1	42.1	44.6	45.9



Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	5%
Low	40	(-20%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	5	0	0	1	1
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	49	43	55
to Sell	42	37	36
Hld's(000)	7829	8212	7948

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.0	12.1
3 yr.	18.7	53.0
5 yr.	17.4	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
31.38	32.66	30.52	29.91	29.28	29.28	30.11	29.86	30.95	45.83	44.52	43.29	51.18	50.22	61.70	63.03	**66.95**	**72.00**	Revenues per sh	**88.75**
4.99	5.22	5.23	5.25	5.33	5.69	5.80	5.83	5.92	6.49	5.50	4.18	5.02	4.89	5.11	4.83	**5.20**	**5.45**	"Cash Flow" per sh	**6.25**
2.40	2.55	2.68	2.68	2.74	2.99	2.97	2.90	2.88	3.05	3.11	2.12	2.78	2.69	2.81	2.56	**2.70**	**2.85**	Earnings per sh A	**3.25**
1.90	1.98	2.05	2.08	2.10	2.12	2.14	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	**2.16**	**2.16**	Div'd Decl'd per sh B ■ †	**2.26**
4.44	3.81	3.13	3.37	2.87	2.84	2.54	2.71	2.76	3.58	4.14	4.50	3.79	3.98	4.05	4.76	**5.85**	**5.40**	Cap'l Spending per sh	**5.25**
22.84	23.60	24.65	25.33	25.96	26.87	27.61	28.00	28.73	29.38	30.33	30.31	30.80	31.31	31.97	32.54	**33.05**	**33.75**	Book Value per sh C	**35.75**
15.77	16.03	16.95	17.24	17.50	17.56	17.28	16.86	16.86	16.36	16.36	16.06	15.76	15.76	15.76	15.76	**15.76**	**15.76**	Common Shs Outst'g D	**15.00**
10.7	11.2	12.2	10.0	10.2	10.1	11.5	14.6	13.5	11.4	13.6	22.6	15.7	17.2	16.5	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.68	.68	.72	.66	.68	.63	.66	.76	.77	.74	.70	1.23	.90	.91	.88	1.03	*Value Line*		Relative P/E Ratio	**.95**
7.4%	6.9%	6.3%	7.8%	7.5%	7.0%	6.3%	5.1%	5.6%	6.2%	5.1%	4.5%	4.9%	4.7%	4.7%	4.4%	*estimates*		Avg Ann'l Div'd Yield	**5.0%**

CAPITAL STRUCTURE as of 3/31/07
Total Debt $413.9 mill. **Due in 5 Yrs** $87.0 mill.
LT Debt $370.9 mill. **LT Interest** $16.9 mill.
(LT interest earned: 4.9x)
Leases, Uncapitalized Annual rentals $3.1 mill.
Pension Assets-12/06 $359.6 mill. **Oblig.** $414.5 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,762,000 shs.
as of 5/1/07
MARKET CAP: $775 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
520.3	503.5	521.9	749.9	728.4	695.5	806.7	791.5	972.5	993.4	**1055**	**1135**	Revenues ($mill)	**1330**
55.1	52.5	51.8	54.2	54.1	36.6	45.4	43.4	45.3	41.4	**43.0**	**45.0**	Net Profit ($mill)	**48.0**
32.3%	35.3%	35.8%	41.4%	- -	36.6%	40.1%	41.9%	36.3%	36.3%	**40.0%**	**40.0%**	Income Tax Rate	**40.0%**
1.2%	1.7%	.8%	1.4%	1.4%	2.3%	1.6%	.9%	.9%	1.5%	**1.0%**	**1.0%**	AFUDC % to Net Profit	**1.0%**
40.4%	40.3%	38.3%	37.4%	28.1%	34.1%	35.5%	38.3%	39.6%	38.8%	**42.5%**	**44.0%**	Long-Term Debt Ratio	**49.5%**
53.3%	53.3%	55.3%	56.1%	64.6%	61.6%	61.8%	59.1%	58.0%	58.8%	**55.5%**	**54.0%**	Common Equity Ratio	**48.5%**
895.0	885.1	875.9	857.1	768.5	790.3	785.3	834.4	868.7	871.8	**945**	**990**	Total Capital ($mill)	**1100**
932.8	928.2	921.4	930.9	561.8	601.7	707.5	745.1	779.5	827.1	**880**	**925**	Net Plant ($mill)	**1050**
7.4%	7.2%	7.3%	7.7%	8.1%	5.4%	6.5%	5.9%	6.0%	5.7%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
10.3%	9.9%	9.6%	10.1%	9.8%	7.0%	9.0%	8.4%	8.6%	7.7%	**8.0%**	**8.0%**	Return on Shr. Equity	**8.5%**
10.9%	10.4%	10.0%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	**8.0%**	**8.5%**	Return on Com Equity E	**9.0%**
3.1%	2.7%	2.5%	3.1%	3.1%	NMF	2.0%	1.7%	2.0%	1.2%	**1.5%**	**2.0%**	Retained to Com Eq	**2.5%**
73%	76%	77%	73%	71%	102%	78%	81%	77%	85%	**82%**	**78%**	All Div'ds to Net Prof	**72%**

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.1	+4.5	-4.2
Avg. Indust. Use (MWH)	1407	1407	1377
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1051	1204	1295
Peak Load, Summer (Mw)	1051	1204	1295
Annual Load Factor (%)	61.0	57.0	50.0
% Change Customers (avg.)	+1.0	+1.3	+.9
Fixed Charge Cov. (%)	374	408	328

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.0%	7.5%	7.5%
"Cash Flow"	-1.0%	-3.5%	4.0%
Earnings	-.5%	-2.5%	3.0%
Dividends	.5%	- -	1.0%
Book Value	2.0%	1.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	263.0	165.3	161.9	201.3	791.5
2005	286.1	189.6	227.9	268.9	972.5
2006	317.2	213.9	239.8	222.5	993.4
2007	343.4	**215**	**235**	**261.6**	**1055**
2008	**375**	**230**	**250**	**280**	**1135**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.46	.35	.28	.60	2.69
2005	1.29	.41	.36	.74	2.81
2006	1.16	.26	.55	.60	2.56
2007	1.37	**.34**	**.34**	**.65**	**2.70**
2008	**1.40**	**.37**	**.38**	**.70**	**2.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.54	.54	.54	.54	2.16
2004	.54	.54	.54	.54	2.16
2005	.54	.54	.54	.54	2.16
2006	.54	.54	.54	.54	2.16
2007	.54	.54			

BUSINESS: CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (79% of '06 income). Customers: 293,000 electric, 71,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 100,000 customers in Northeast (4% of '06 income). Investments were 17% of '06 income. Electric revenue breakdown, '06: residential, 51%; commercial, 32%; industrial, 7%; other, 10%. Generating sources, '06: hydro, 3%; purchased, 97%. Fuel costs: 66% of revenues. '06 reported depreciation rate (utility): 3.0%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

We have raised our 2007 earnings estimate for CH Energy Group by $0.10 a share, to $2.70. This past winter, the utility's service territory was not hit with the severe storms that occurred in the first quarter of 2006. These more favorable weather conditions enabled first-quarter earnings to rise significantly. In addition, the price elasticity that was affecting electric and gas sales appears to be abating. On the nonregulated side, the Griffith Energy subsidiary is performing better, thanks to acquisitions (see below) and increased margins. Our earnings estimate is within CH Energy's targeted range of $2.55-$2.80 a share. We have boosted our 2008 forecast by $0.15 a share, to $2.85. The company has not yet provided guidance for next year.

CH Energy is growing through acquisitions. In 2006, Griffith Energy closed nine deals for a total of $3.6 million. So far in 2007, the acquisitions have been bigger: three for a total of $9.9 million. These purchases boosted Griffith's customer base by 17%, to over 100,000. In recent years, CH Energy has also made investments in an ethanol plant, a biomass-to-energy facility, and wind projects. The company has ample cash and borrowing capacity to fund acquisitions.

Finances are sound. Although the fixed-charge coverage declined in 2006, it remains well above the industry average. The common-equity ratio is high, too. CH Energy merits a Financial Strength Rating of A, and its stock is top-ranked for Safety.

CH Energy wants to resume dividend growth. The board of directors hasn't raised the dividend since the late 1990s. The current payout ratio is on the high side, so we expect no dividend increase this year or next. The company has set a goal of boosting the disbursement by 5% by 2011, which we think is achievable. We have adjusted our 3- to 5-year projections accordingly.

This stock is untimely, but its yield is more than one percentage point above the norm for the electric utility industry as a whole. Even though we have boosted our 2010-2012 dividend projections, however, total-return potential over that time is subpar.

Paul E. Debbas, CFA *June 1, 2007*

(A) Diluted earnings. Excl. nonrecurring gains: '92, 10¢; '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't add to total due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '06: $299.2 mill., $18.98/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 10.6%; earned on avg. com. eq., '06: 8.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

CLECO CORPORATION NYSE-CNL

RECENT PRICE 26.15 | P/E RATIO 21.1 (Trailing: 19.2, Median: 13.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Raised 8/11/06
SAFETY 3 Lowered 1/3/03
TECHNICAL 4 Lowered 3/16/07
BETA 1.30 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	14.6	16.6	18.1	17.8	28.3	27.3	24.9	18.4	20.8	24.4	26.2	27.8
Low:	12.6	12.4	14.3	14.1	15.1	19.2	9.7	11.0	16.2	18.9	20.5	24.3

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

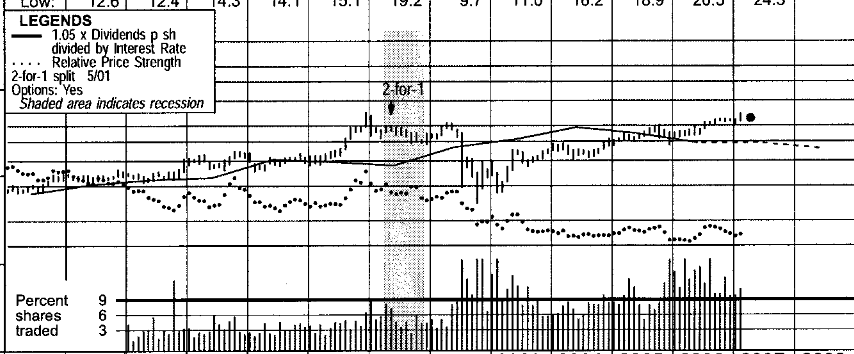
	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	1	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	77	109	90
to Sell	62	46	81
Hld's(000)	34731	41017	40413



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.8	12.0
3 yr.	57.0	41.4
5 yr.	54.5	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
7.58	7.88	8.54	8.48	8.79	9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.25	18.20	19.15	Revenues per sh	23.50
1.76	1.78	1.74	1.85	1.99	2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.50	2.50	2.60	"Cash Flow" per sh	3.50
.96	.97	.89	.96	1.04	1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.25	1.30	Earnings per sh A	1.75
.66	.69	.71	.73	.75	.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	Div'd Decl'd per sh B ■ †	1.20
1.23	1.44	1.15	1.24	1.29	1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	5.50	8.80	6.15	Cap'l Spending per sh	1.75
6.76	7.06	7.29	7.56	7.91	8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.05	15.55	16.10	Book Value per sh C	18.00
44.48	44.61	44.77	44.78	44.85	44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	58.00	59.00	60.00	Common Shs Outst'g D	63.00
10.7	12.5	14.3	12.1	11.6	11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	Bold figures are		Avg Ann'l P/E Ratio	14.0
.68	.76	.84	.79	.78	.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.94	Value Line		Relative P/E Ratio	.95
6.4%	5.7%	5.5%	6.2%	6.2%	5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	estimates		Avg Ann'l Div'd Yield	4.8%

CAPITAL STRUCTURE as of 9/30/06
Total Debt $629.4 mill. Due in 5 Yrs $230.0 mill.
LT Debt $584.4 mill. LT Interest $38.0 mill.
Excludes $174.2 mill. off-balance-sheet financing.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $53.0 mill.
Pension Assets-12/05 $225.3 mill. Oblig. $256.2 mill.
Pfd Stock $21.0 mill. Pfd Div'd $1.8 mill.
Includes 210,175 shares 8.125%, each convertible into 9.6 common shares, callable at $100.8125.
Common Stock 57,488,574 shs.
as of 10/31/06
MARKET CAP: $1.5 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
456.2	515.2	768.2	820.0	1058.6	721.2	874.6	745.8	920.2	1000.7	1075	1150	Revenues ($mill)	1475
52.5	53.8	56.8	69.3	72.3	74.2	61.2	66.1	75.0	74.7	75.0	80.0	Net Profit ($mill)	115
34.6%	33.1%	32.4%	33.5%	34.7%	36.9%	37.2%	35.2%	39.2%	36.0%	38.5%	38.5%	Income Tax Rate	38.5%
1.5%	3.2%	10.6%	12.1%	16.7%	12.6%	5.8%	7.5%	4.3%	19.0%	40.0%	51.0%	AFUDC % to Net Profit	4.0%
46.2%	43.6%	56.2%	57.9%	55.2%	60.0%	64.4%	44.5%	46.3%	41.0%	45.5%	51.5%	Long-Term Debt Ratio	51.5%
49.2%	51.9%	41.0%	39.7%	42.4%	38.2%	33.8%	53.1%	52.0%	57.5%	53.5%	47.5%	Common Equity Ratio	48.0%
792.1	786.2	1032.1	1139.2	1134.7	1448.7	1408.5	1011.6	1315.9	1513.7	1725	2035	Total Capital ($mill)	2350
1025.6	1089.8	1211.6	1232.8	1224.7	1566.2	1417.1	1060.0	1188.7	1304.9	1755	2050	Net Plant ($mill)	2250
8.1%	8.3%	6.9%	8.3%	8.6%	7.1%	6.7%	8.9%	7.1%	6.0%	5.5%	5.5%	Return on Total Cap'l	6.5%
12.3%	12.1%	12.5%	14.4%	14.2%	12.8%	12.2%	11.8%	10.6%	8.5%	8.0%	8.0%	Return on Shr. Equity	10.0%
12.9%	12.7%	12.9%	14.9%	14.6%	13.1%	12.5%	11.9%	10.7%	8.5%	8.0%	8.0%	Return on Com Equity E	10.0%
3.9%	3.8%	4.2%	6.5%	6.5%	5.6%	3.5%	3.9%	4.1%	3.0%	2.0%	2.5%	Retained to Com Eq	3.0%
71%	71%	69%	57%	57%	58%	72%	68%	62%	67%	73%	70%	All Div'ds to Net Prof	68%

ELECTRIC OPERATING STATISTICS

	2003	2004	2005
% Change Retail Sales (KWH)	+1.5	+2.6	-.2
Avg. Indust. Use (MWH)	3806	4194	4245
Avg. Indust. Revs. per KWH (¢)	5.41	5.67	7.22
Capacity at Peak (Mw)	2216	2190	2030
Peak Load, Summer (Mw)	1990	1940	2014
Annual Load Factor (%)	58.2	60.0	57.2
% Change Customers (avg.)	+1.3	+1.8	+.8
Fixed Charge Cov. (%)	181	174	247

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	7.0%	2.0%	4.5%
"Cash Flow"	4.0%	2.5%	3.5%
Earnings	3.5%	1.0%	4.0%
Dividends	2.0%	2.0%	4.0%
Book Value	4.5%	4.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	166.6	166.3	229.4	183.5	745.8
2005	172.1	194.1	283.7	270.3	920.2
2006	223.4	251.0	294.1	232.2	1000.7
2007	240	270	320	245	1075
2008	255	285	350	260	1150

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.26	.22	.56	.27	1.32
2005	.18	.40	.82	.03	1.42
2006	.23	.44	.50	.19	1.36
2007	.20	.35	.50	.20	1.25
2008	.20	.37	.53	.20	1.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.225	.225	.225	.225	.90
2004	.225	.225	.225	.225	.90
2005	.225	.225	.225	.225	.90
2006	.225	.225	.225	.225	.90
2007	.225				

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 267,000 customers in central Louisiana. Through subsidiaries, has about 1,350 megawatts of wholesale capacity. Electric revenue breakdown, '05: residential, 48%; commercial, 22%; industrial, 17%; other, 13%. Largest industrial customers are paper mills and other wood-product industries. Generating sources, '05: coal & lignite, 34%; gas & oil, 17%; purchased, 49%. Fuel costs: 62% of revenues. '05 reported deprec. rate (utility): 3.3%. Has 1,150 employees. Chairman: J. Patrick Garrett. President & CEO: Michael H. Madison. Inc.: Louisiana. Address: P.O. Box 5000, Pineville, Louisiana 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's earnings are likely to decline in 2007. Some unusual items that benefited profits in 2006 will not occur this year. One of them is the $0.17 a share of income that Cleco booked from drawdowns of a letter of credit from Calpine after the latter company filed for bankruptcy protection (see below). A major planned outage at a generating unit in the fourth quarter will reduce earnings by $0.06 a share. And, average shares outstanding will rise due to a stock sale last year. A significant increase in the Allowance for Funds Used During Construction stemming from the building of Rodemacher Unit 3 will offset these factors to some extent. Cleco expects its earnings to wind up in a range of $1.20-$1.30 a share in 2007. We look for earnings to rise modestly in 2008 because Cleco won't have the aforementioned outage at the generating unit.

Construction of Rodemacher 3 is going well. Cleco expects to spend $1 billion to build the 600-megawatt facility, which will be powered by solid fuel (probably petroleum coke). It is due on line by late 2009. The unit will lessen the utility's dependence on natural gas and purchased power, the prices of which are costly and volatile. The company will probably issue some debt this year to help finance construction of Rodemacher 3, but the amount and timing of any issuances have not yet been determined.

Cleco is trying to resolve its problems regarding the Acadia project. Calpine had a contract to supply gas to Acadia and market its output, but rejected the contract after it filed for bankruptcy protection in late 2005. Acadia then became a merchant power plant, selling electricity into the market, and is unprofitable for Cleco. The company has stated that it hopes to make an announcement soon regarding Acadia.

Cleco's long-term prospects look brighter than its present ones. By the 2010-2012 period, with Rodemacher 3 (presumably) in the rate base, the company's earning power will be much higher. We expect dividend growth to resume over that time, too. At the current quotation, however, these untimely shares offer only average (by utility standards) 3- to 5-year total-return potential.

Paul E. Debbas, CFA *March 30, 2007*

(A) Primary EPS through '96, dil. thereafter. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; losses from disc. ops.: '00, 14¢; '01, 4¢. '04 & '05 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '05: $4.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '06: 11.65%; earned on avg. com. eq., '05: 12.7%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	50
Price Growth Persistence	60
Earnings Predictability	70

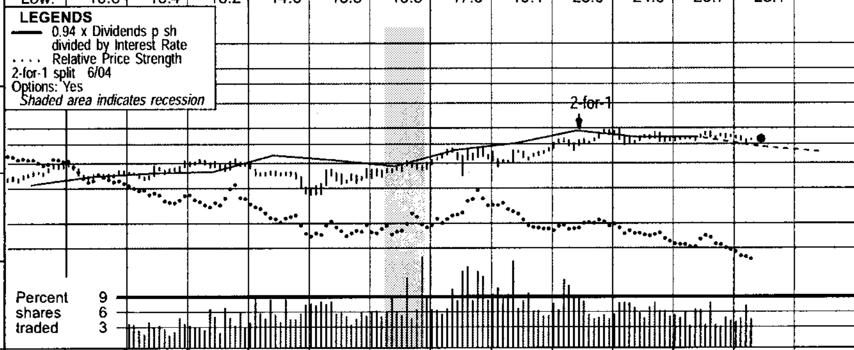
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 26.58 | P/E RATIO 22.2 (Trailing: 20.0 Median: 13.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 5 Lowered 12/1/06
SAFETY 2 Raised 2/15/02
TECHNICAL 4 Lowered 3/30/07
BETA .75 (1.00 = Market)

High:	19.8	20.8	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5
Low:	16.6	16.4	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	25.1

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	2	0	0	0	2	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	3	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	74	87	84
to Sell	68	52	67
Hld's(000)	26259	26682	27384

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	2.6	12.1
3 yr.	21.7	53.0
5 yr.	43.2	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
22.71	20.83	20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	*29.95*	*30.40*	Revenues per sh	*34.00*
2.37	2.51	2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	*3.15*	*3.30*	"Cash Flow" per sh	*3.75*
1.20	1.27	1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	*1.30*	*1.40*	Earnings per sh A	*1.75*
1.11	1.13	1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■ †	*1.24*
3.42	4.03	4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	*2.80*	*3.55*	Cap'l Spending per sh	*2.25*
12.18	11.06	11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	*13.60*	*13.95*	Book Value per sh C	*15.00*
47.73	49.52	55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	*83.50*	*85.50*	Common Shs Outst'g D	*87.00*
14.2	15.3	15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.91	.93	.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	*Value Line*		Relative P/E Ratio	*.95*
6.5%	5.8%	6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*
						1464.0	1485.2	1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	*2500*	*2600*	Revenues ($mill)	*2950*
						103.3	113.2	111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	*110*	*125*	Net Profit ($mill)	*155*
						34.9%	33.5%	33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	*40.0%*	*39.0%*	Income Tax Rate	*40.0%*
						16.5%	14.2%	6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	*9.0%*	*12.0%*	AFUDC % to Net Profit	*6.0%*
						43.4%	44.7%	47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*48.5%*
						44.0%	43.1%	41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	*47.5%*	*47.5%*	Common Equity Ratio	*50.0%*
						1851.3	1918.9	2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	*2395*	*2510*	Total Capital ($mill)	*2625*
						2019.6	2093.4	2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	*2725*	*2865*	Net Plant ($mill)	*2975*
						7.0%	7.4%	6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
						9.8%	10.7%	10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	*9.5%*	*10.0%*	Return on Shr. Equity	*11.5%*
						10.6%	11.4%	11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	*9.5%*	*10.0%*	Return on Com Equity E	*12.0%*
						3.0%	1.8%	1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	*.5%*	*1.5%*	Retained to Com Eq	*3.5%*
						76%	87%	88%	84%	63%	63%	64%	87%	85%	93%	*94%*	*87%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $1309.5 mill. **Due in 5 Yrs** $386.3 mill.
LT Debt $1123.2 mill. **LT Interest** $62.6 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.3x)
Pension Assets-12/06 $875.3 mill. **Oblig.** $985.6 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100. Sinking fund ends 2018.
Common Stock 81,471,220 shs.
as of 2/21/07
MARKET CAP: $2.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.9	+.3	+.3
Avg. Indust. Use (MWH)	6816	6718	6623
Avg. Indust. Revs. per KWH (¢)	12.86	15.21	17.38
Capacity at Yearend (Mw)	2171	2184	2204
Peak Load, Winter (Mw)	1694	1641	1685
Annual Load Factor (%)	71.5	74.1	72.5
% Change Customers (yr-end)	+1.2	+1.7	+1.2
Fixed Charge Cov. (%)	335	325	301

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.0%	2.0%	*4.0%*
"Cash Flow"	1.5%	-.5%	*3.0%*
Earnings	.5%	-1.0%	*4.0%*
Dividends	.5%	--	*Nil*
Book Value	1.5%	2.0%	*.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	437.1	461.8	506.8	518.4	1924.1
2005	472.6	522.3	595.9	624.8	2215.6
2006	574.9	605.0	673.9	607.1	2460.9
2007	*625*	*625*	*625*	*625*	*2500*
2008	*650*	*650*	*650*	*650*	*2600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.40	.14	.51	.31	1.36
2005	.30	.35	.46	.35	1.46
2006	.40	.33	.40	.20	1.33
2007	*.35*	*.30*	*.35*	*.30*	*1.30*
2008	*.38*	*.32*	*.38*	*.32*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.31	.31	.31	.31	1.24
2004	.31	.31	.31	.31	1.24
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31				

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 434,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '06: residential, 34%; commercial, 34%; large light & power, 32%. Generating sources, '06: oil, 62%; purchased, 38%. Fuel costs: 52% of revs. '06 reported depr. rate (utility): 3.9%. Has 3,400 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

One of Hawaiian Electric's utilities has received an interim order in its rate case. The Hawaii commission approved Hawaii Electric Light Company's (HELCO) settlement for a $24.6 million (7.6%) rate hike, based on a 10.7% return on 51.19% equity. Considering that HELCO received most of the $29.9 million it requested, we consider this a good outcome. The order calls for the utility to write off some plant costs, which will cause it to take a $7 million ($0.09-a-share) charge against first-quarter earnings. We will *exclude* this from our presentation as a nonrecurring item.

The company's other two utilities have rate cases pending. Hawaiian Electric Company (HECO) is seeking a $99.6 million (7.1%) tariff rate hike, based on an 11.25% return on a 55.1% common-equity ratio. HECO still hasn't received a final order in its previous case, in which it was granted an interim increase of $41.4 million (3.3%) based on a 10.7% ROE. Maui Electric Company (MECO) has requested a $19 million (5.3%) rate increase based on an 11.25% return on a 55.1% common-equity ratio. HECO and MECO should get interim decisions in late 2007 and early 2008, respectively. Separately, each utility will benefit from a regulatory order that allows the recovery of demand-side management program costs and provides for performance-based incentives.

The aforementioned regulatory activity was prompted largely by rising expenses. Higher costs have hurt the company's earnings in recent years, and this is likely to continue in 2007. Rate relief should help beginning in 2008, but we project that, even over the 3- to 5-year period, profits won't reach a level that would make a dividend increase probable. At least there appears to be no risk of a dividend cut for the time being.

Profits at American Savings Bank (ASB) are down. ASB is facing a lower interest-rate margin, higher credit costs, and higher noninterest expense. At least asset quality is still good.

This untimely stock's main attraction is its high yield. For the 3- to 5-year period, however, it is trading well within our 2010-2012 Target Price Range, and total-return potential over that time is poor.

Paul E. Debbas, CFA *May 11, 2007*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; 1Q '07, *(9¢)*. Next egs. due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '06: $2.45/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '05: HECO, 10.7% (interim); in '01: HELCO, 11.5%; in '99: MECO, 10.94%; earned on avg. com. eq., '06: 9.3%. Regulat. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

MGE ENERGY INC. NDQ-MGEE

RECENT PRICE **34.32** | P/E RATIO **16.3** (Trailing: 16.7 Median: 16.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 3 Raised 8/25/06
SAFETY 1 New 1/3/03
TECHNICAL 4 Lowered 3/30/07
BETA .80 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	27.5	23.8	23.8	23.9	23.7	27.8	30.1	35.8	36.4	38.8	37.0	36.8
Low:	19.6	18.5	20.6	16.4	16.8	20.9	24.6	25.0	27.6	30.5	29.2	33.1

Target Price Range 2010 2011 2012

2010-12 PROJECTIONS

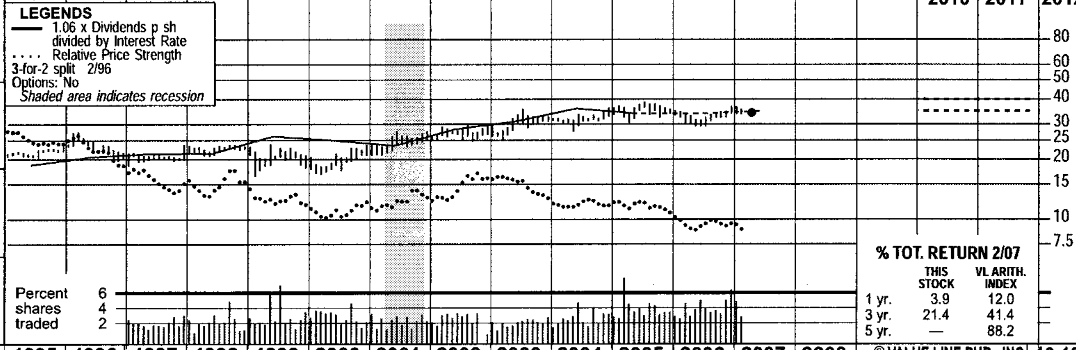
	Price	Gain	Ann'l Total Return
High	40	(+15%)	8%
Low	35	(Nil)	5%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	36	37	44
to Sell	28	21	20
Hld's(000)	5521	5690	6060



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.9	12.0
3 yr.	21.4	41.4
5 yr.	—	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.47	14.21	15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.50	24.90	25.60	Revenues per sh	28.00
2.83	2.79	2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.05	3.30	3.40	"Cash Flow" per sh	4.10
1.52	1.45	1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	2.10	2.20	Earnings per sh A	2.55
1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.41	1.43	Div'd Decl'd per sh B ■	1.47
1.24	.77	1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	3.95	4.00	4.00	Cap'l Spending per sh	4.00
10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	16.95	17.95	18.70	Book Value per sh	19.45
16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.70	20.70	20.70	Common Shs Outst'g C	20.70
11.3	14.3	15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	17.1	Bold figures are		Avg Ann'l P/E Ratio	15.0
.72	.87	.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.92	Value Line		Relative P/E Ratio	1.00
6.8%	5.7%	5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	estimates		Avg Ann'l Div'd Yield	4.6%

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
264.7	249.8	274.0	324.1	333.7	347.1	401.5	424.9	513.4	507.5	515	530	Revenues ($mill)	580
22.5	22.2	23.8	27.4	27.2	29.2	30.6	33.8	32.1	42.4	44.0	46.0	Net Profit ($mill)	43.0
37.5%	37.1%	36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	38.2%	38.0%	38.0%	38.0%	Income Tax Rate	38.0%
.2%	.9%	1.9%	1.9%	2.2%	--	--	--	2.2%	1.7%	1.8%	1.8$	AFUDC % to Net Profit	2.0%
41.8%	46.7%	44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	39.3%	39.5%	39.5%	39.0%	Long-Term Debt Ratio	39.0%
58.2%	53.3%	55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	60.5%	60.5%	61.0%	Common Equity Ratio	61.0%
310.8	342.0	334.3	383.7	373.9	419.5	465.3	540.5	566.2	590	615	635	Total Capital ($mill)	660
284.7	258.6	260.1	342.8	401.2	451.5	537.5	607.4	667.7	675	680	690	Net Plant ($mill)	700
8.8%	8.0%	8.8%	8.8%	9.0%	8.1%	7.8%	7.1%	6.6%	8.5%	8.5%	9.0%	Return on Total Cap'l	7.5%
12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	10.5%	12.0%	12.0%	Return on Shr. Equity	10.5%
12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	10.5%	12.0%	12.0%	Return on Com Equity D	10.5%
1.0%	.7%	1.5%	2.9%	2.3%	2.6%	2.5%	2.3%	1.2%	3.5%	4.0%	4.0%	Retained to Com Eq	3.0%
92%	94%	89%	79%	82%	79%	79%	77%	87%	68%	66%	64%	All Div'ds to Net Prof	71%

CAPITAL STRUCTURE as of 9/30/06
Total Debt $289.4 mill. **Due in 5 Yrs** $65.0 mill.
LT Debt $207.4 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/05 $116.7 mill.
Obligation $173.5 mill.

Pfd Stock None

Common Stock 20,670,572 shs.
as of 10/31/06
MARKET CAP: $700 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2003	2004	2005
% Change Retail Sales (KWH)	-1.6	+5.5	-0.7
Avg. Indust. Use (MWH)	4629	4624	4293
Avg. Indust. Revs. per KWH (¢)	4.11	4.40	4.37
Capacity at Peak (Mw)	768	763	812
Peak Load, Summer (Mw)	664	714	690
Annual Load Factor (%)	48.1	59.1	48.1
% Change Customers (avg.)	+.5	+1.0	+1.6
Fixed Charge Cov. (%)	352	388	352

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	4.0%	5.5%	.5%
"Cash Flow"	--	-5.0%	.5%
Earnings	1.0%	2.0%	6.0%
Dividends	1.0%	1.0%	.5%
Book Value	3.0%	6.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	135.4	85.4	86.8	117.3	424.9
2005	138.9	100.5	114.4	159.6	513.4
2006	158.6	99.7	110.6	138.6	507.5
2007	160	103	114	138	515
2008	164	107	118	141	530

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.74	.30	.48	.25	1.77
2005	.40	.27	.48	.42	1.57
2006	.56	.34	.62	.54	2.06
2007	.58	.35	.63	.54	2.10
2008	.60	.38	.65	.57	2.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.336	.336	.338	.338	1.35
2004	.338	.338	.342	.342	1.36
2005	.342	.342	.345	.345	1.37
2006	.345	.345	.348	.348	1.39
2007	.348				

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to nearly 132,000 customers in a 250-square-mile area of Dane County and gas service to 129,000 customers in 1,375 square miles in seven counties in Wisconsin. Electric revenue breakdown, '05: residential, 33%; commercial, 48%; industrial, 6%; public authorities, 7%; other, 6%. Generating sources, '05: fossil-fueled steam, 62%; purchased power, 37%; other, 1%. Fuel costs: 43% of revenues. '05 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

MGE Energy posted sharply improved 2006 results. Share net at the electric utility and natural gas distributor increased 31%, year over year, to $2.06, on 1% lower revenue of $507.5 million. Mild weather across MGE's south-central and western Wisconsin service area limited the use of electricity/gas for residential heating and cooling. Still, share net benefited from sharply lower costs for electric fuel and purchased power. Hurricane-related damage to the nation's infrastructure had MGE paying more for fuel and purchased power in 2005. Thankfully, the 2006 hurricane season caused little, if any, supply disruptions or spikes in energy prices.

We look for more normalized earnings growth of 5% this year followed by low- to mid-single digit (per-annum) advances out to 2010-2012. Peak energy demand should increase 3% or so annually, net the effect of conservation initiatives. MGE should benefit from favorable demographics within its Dane County service area. Over the past few years, the population of Dane Country has been growing nearly 50% faster than the national average. Commercial and residential development in and around the city of Madison, in particular, should drive utility demand. Madison, including immediate suburbs, has a population of some 400,000 people and is home to the University of Wisconsin.

MGE may appeal to more environmentally conscious investors. The utility is aggressively developing renewable energy (R-E) sources and ought to easily meet state R-E mandates. MGE's 18-turbine addition to the Top of Iowa Wind Farm should triple its wind-generating capacity, to 45 megawatts. The utility also plans to eliminate coal burning at its Blount Generating Station and secure new cleaner-coal capacity.

MGE shares are ranked 3 (Average) for year ahead price performance. They've sold off since our December report and are now trading slightly below our our 3- to 5-year Target Price Range. The current quotation marks a decent entry point conservative, income-oriented investors. The current dividend yield, at 4.0%, is attractive, and regular, albeit modest, dividend increases are likely.

Nils C. Van Liew *March 30, 2007*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late April. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for stock split. (D) Rate allowed on common equity in '02: 12.9%; earned on average common equity, '02: 13.0%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	75

NORTHEAST UTILITIES NYSE-NU

RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD
32.24	23.0	(Trailing: 22.4 / Median: NMF)	1.20	2.5%

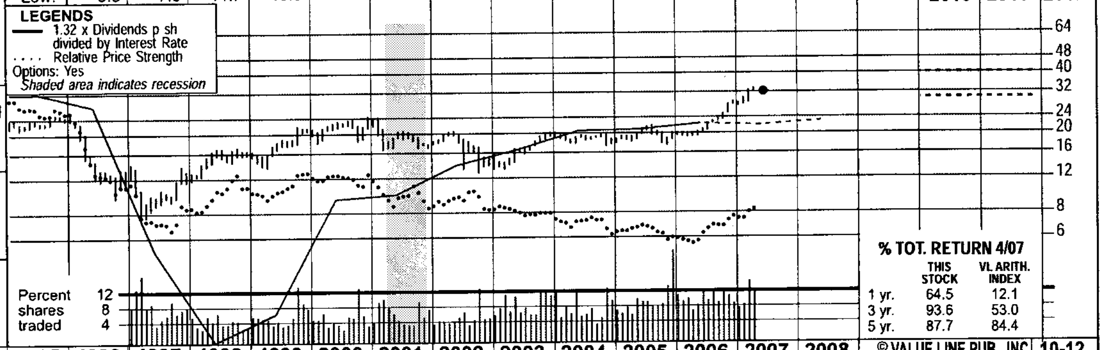
VALUE LINE

TIMELINESS **3** Raised 7/19/02
SAFETY **3** Raised 9/6/02
TECHNICAL **3** Lowered 5/25/07
BETA .90 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	25.3	14.3	17.3	22.0	24.6	24.3	20.7	20.3	20.3	22.0	28.9	33.6
Low:	9.5	7.6	11.7	13.6	18.0	16.6	12.7	13.1	17.2	17.3	19.1	27.2

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.32 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	8%
Low	30	(-5%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	1	0	0	5
to Sell	0	0	0	0	1	1	0	0	5

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	98	87	130
to Sell	88	85	79
Hld's(000)	119815	114648	113929

Percent shares traded 12 8 4

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	64.5	12.1
3 yr.	93.6	53.0
5 yr.	87.7	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
23.09	24.03	29.19	29.15	29.51	29.52	29.46	28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	**37.50**	**38.95**	Revenues per sh	**43.00**
4.66	5.13	5.86	6.26	6.02	3.77	2.68	3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	2.34	**3.20**	**3.65**	"Cash Flow" per sh	**4.55**
2.12	2.02	1.60	2.30	2.24	.01	d1.05	d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	**1.40**	**1.55**	Earnings per sh (A)	**1.80**
1.76	1.76	1.76	1.76	1.76	1.38	.25	--	.10	.40	.45	.53	.58	.63	.68	.73	**.78**	**.83**	Div'd Decl'd per sh (B)■	**.98**
2.10	2.37	2.49	2.31	1.97	1.85	1.85	1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	**7.70**	**5.70**	Cap'l Spending per sh	**4.25**
15.73	16.24	17.89	18.48	19.08	17.73	16.34	15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	**18.90**	**19.75**	Book Value per sh (C)	**22.60**
119.25	133.86	124.33	124.96	127.05	128.44	130.18	130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	**156.20**	**158.20**	Common Shs Outst'g (D)	**164.20**
10.1	12.3	16.6	10.0	10.3	NMF	--	--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	*Bold figures are*		Avg Ann'l P/E Ratio	**19.5**
.65	.75	.98	.66	.69	NMF	--	--	--	--	.72	.88	.76	1.10	1.05	1.46	*Value Line*		Relative P/E Ratio	**1.30**
8.3%	7.1%	6.6%	7.7%	7.6%	8.9%	2.4%	--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**2.8%**

CAPITAL STRUCTURE as of 3/31/07
Total Debt $3772 mill. **Due in 5 Yrs** $2624 mill.
LT Debt $3264 mill. **LT Interest** $164.1 mill.

(LT interest earned: 1.4x)

Pension Assets-12/06 $2.4 bill. **Oblig.** $2.3 bill.
Pfd Stock $116.2 mill. **Pfd Div'd** $5.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.

Common Stock 154,553,804 shs. **as of 4/30/07**

MARKET CAP: $5.0 billion (Large Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
3834.8	3767.7	4471.3	5876.6	6873.8	5216.3	6069.2	6686.7	5507.3	6884.4	**5860**	**6160**	Revenues ($mill)	**7060**
d96.1	d11.8	d127.0	d14.4	186.4	144.2	162.7	122.1	128.5	126.2	**220**	**250**	Net Profit ($mill)	**300**
--	NMF	--	--	--	--	32.1%	29.8%	30.8%	30.8%	**31.0%**	**31.0%**	Income Tax Rate	**31.0%**
--	--	--	--	--	9.2%	7.1%	6.8%	6.8%	21.5%	**6.0%**	**7.0%**	AFUDC % to Net Profit	**5.0%**
58.5%	57.9%	49.9%	45.7%	65.9%	64.3%	63.9%	64.2%	63.2%	58.7%	**50.5%**	**51.0%**	Long-Term Debt Ratio	**49.0%**
33.8%	35.2%	42.7%	48.8%	32.4%	33.9%	34.3%	34.0%	35.1%	39.7%	**47.5%**	**47.5%**	Common Equity Ratio	**49.5%**
6285.3	5821.7	4876.0	4546.6	6544.7	6513.2	6591.6	6749.4	6923.2	7052.0	**6230**	**6605**	Total Capital ($mill)	**7485**
6463.2	6170.9	3947.4	3547.2	3822.1	4728.4	5429.9	5864.2	6417.2	6242.2	**7170**	**7740**	Net Plant ($mill)	**8810**
.7%	2.1%	.0%	1.9%	4.6%	4.1%	4.2%	2.8%	3.5%	2.9%	**4.5%**	**5.0%**	Return on Total Cap'l	**5.0%**
NMF	NMF	NMF	NMF	8.3%	6.2%	6.8%	5.1%	5.0%	4.3%	**7.0%**	**7.5%**	Return on Shr. Equity	**8.0%**
NMF	NMF	NMF	NMF	8.5%	6.3%	6.9%	5.1%	5.1%	4.3%	**7.0%**	**8.0%**	Return on Com Equity (E)	**8.0%**
NMF	NMF	NMF	NMF	5.6%	3.2%	3.7%	1.6%	1.5%	.3%	**3.0%**	**3.5%**	Retained to Com Eq	**3.5%**
NMF	NMF	NMF	NMF	37%	51%	48%	70%	72%	94%	**58%**	**55%**	All Div'ds to Net Prof	**55%**

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.6	+9.7	-4.1
Avg. Indust. Use (MWH)	814	809	776
Avg. Indust. Revs. per KWH (¢)	8.26	8.19	7.76
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+2.0	+.2
Fixed Charge Cov. (%)	168	156	79

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.5%	1.5%	2.5%
"Cash Flow"	-2.0%	-8.0%	1.0%
Earnings	-5.0%	--	12.0%
Dividends	-8.5%	16.5%	6.5%
Book Value	--	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1838	1524	1668	1657	6687
2005	1407	1238	1424	1438	5507
2006	2147	1661	1593	1483	6884
2007	1704	**1350**	**1400**	**1406**	**5860**
2008	**1780**	**1425**	**1475**	**1480**	**6160**

Cal-endar	EARNINGS PER SHARE (A) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.53	.18	d.06	.26	.91
2005	.45	.14	.06	.33	.98
2006	d.13	.09	.67	.19	.82
2007	.49	**.15**	**.45**	**.31**	**1.40**
2008	**.53**	**.17**	**.50**	**.35**	**1.55**

Cal-endar	QUARTERLY DIVIDENDS PAID (B)■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.138	.138	.15	.15	.58
2004	.15	.15	.163	.163	.63
2005	.163	.163	.175	.175	.68
2006	.175	.175	.188	.188	.73
2007	.188	.188	.20		

BUSINESS: Northeast Utilities is the parent of the NU sys, which is the largest utility in New England and serves two million electricity and gas customers. Connecticut Light & Power provides service to most of Conn; Public Service Co. of New Hampshire supplies power to three quarters of New Hampshire's population; Western Massachusetts Electric Co. serves the western half of Mass. Acq'd Yankee Energy 3/00. 2006 revs: resid'l, 48%; comm'l, 39%; ind'l, 12%; other 1%. Gen. sources: fossil (steam), hydro, and purchased power. Fuel & Purch. Pwr. costs: 67% of '06 revs. '06 deprec. rate: 3.2%. Has 5,867 employees. Chrmn, Pres. & CEO: Charles W. Shivery. Inc.: CT. Addr.: P.O. Box 270, Hartford, CT 06141. Tel.: 800-999-7269. Web: www.nu.com.

Northeast Utilities has three transmission projects under way. The largest is a 69-mile line from Norwalk to Middletown, in which NU has an 80% stake. To satisfy landowners whose property lies en route, 20 miles will be built underground. That raised the estimated cost several hundred million dollars, to $1.3 billion. On completion in 2009, the facility will increase energy imports into southwest Connecticut by some 1,300 megawatts. NU is also constructing a nine-mile underground line between Norwalk and Stamford, for $183 million, to strengthen connections in that area. Too, NU has a 50% stake in an 11-mile undersea cable between Connecticut and Long Island that is 35 years old and will be replaced to improve reliability. The unit is due on line next year at a cost of $144 million. Management projects that these additions and infrastructure upgrades will cost $4 billion through 2010. Debt and equity offerings will be needed to cover the outlays.

One rate order is in place. Two remain outstanding. Last March, NU received $37.7 million in New Hampshire in addition to a temporary hike of $24.5 million the previous July. In Connecticut, it awaits a regulatory decision on a $19.4 million settlement agreement with interested parties to cover the cost of the Yankee Gas liquified natural gas storage facility, which will be operative in the coming heating season. Finally, NU will soon file for higher electric and gas distribution rates at its Connecticut L&P utility. An order here is expected in December.

Earnings should have no difficulty surpassing last year's weak results. (Note: Our 2006 presentation excludes gains of $2.23 a share from the sale of high-risk, generation assets, because of their nonrecurring nature.) Based on a full year of rate relief in New Hampshire and recovery of transmission expenditures on a regular basis, we estimate 2007 earnings will rise 70%, to $1.40 a share. A much smaller increase is likely next year.

The stock is an average utility investment. Though the year-ahead yield is below the industry norm, dividend growth potential to 2010-2012 exceeds that of the group. At the share's recent price, total return prospects are only average.

Arthur H. Medalie *June 1, 2007*

(A) Basic egs. EPS may not add due to change in share count. Excl. nonrecur. items: '99, $1.40; '01, 42¢; '02, 10¢; '03, d32¢; '04, d7¢; 1Q, '05, d$1.36; '06, $2.23. Incl. ind. restruct. chgs: '00, $1.51. Next egs rpt early Aug. (B) Div'd suspended 2Q, '97; reinstated 4Q, '99. Div'ds hist. paid late Mar., June, Sep., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs '06: $21.59/sh. (D) In mill. (E) Rate allowed on com. eq.: MA., '99: 11%; CT, '03: 9.85%; NH, '97: 11%. Earned on avg. com. eq.: '06, 4.8%. Regulatory Climate: Below avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	25

NSTAR NYSE-NST

RECENT PRICE	36.33	P/E RATIO	17.7 (Trailing: 18.3; Median: 14.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	3.7%	VALUE LINE

TIMELINESS	4	Lowered 12/8/06
SAFETY	1	Raised 6/11/99
TECHNICAL	4	Lowered 5/25/07

BETA .80 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(-5%)	4%

Insider Decisions

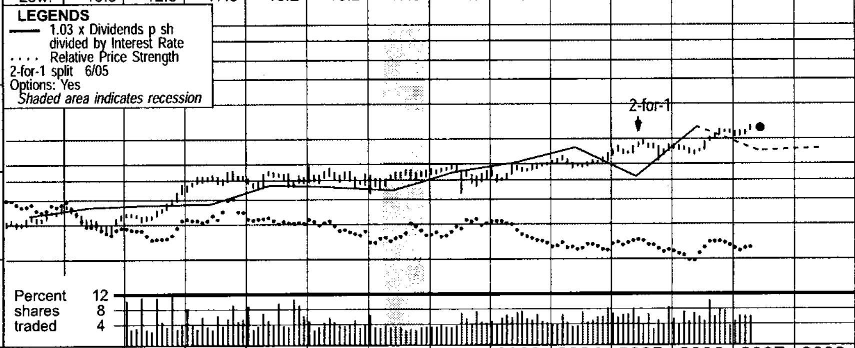
	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	2	2	0	6	0	0	0	0	0
to Sell	2	2	0	6	1	0	0	2	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	96	115	123
to Sell	94	84	85
Hld's(000)	45568	47591	48400

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	15.1	19.2	22.5	22.3	23.5	22.6	24.1	24.5	27.2	31.5	35.9	37.4
Low:	10.9	12.3	17.5	18.2	18.2	17.0	17.0	19.3	22.7	24.9	26.5	32.7

LEGENDS
—— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/05
Options: Yes
Shaded area indicates recession



Percent shares traded 12 8 4

Target Price Range

2010	2011	2012

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	34.9	12.1
3 yr.	68.0	53.0
5 yr.	95.6	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.69	15.77	16.42	17.00	16.96	17.17	18.31	17.19	15.94	25.45	30.09	25.64	27.48	27.73	30.36	33.50	***33.70***	***35.80***	Revenues per sh	***43.00***
2.87	2.94	2.98	3.35	3.11	3.65	3.66	3.84	3.04	3.78	3.81	3.95	3.98	4.09	5.00	5.40	***5.60***	***5.90***	"Cash Flow" per sh	***6.75***
.98	1.05	1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.93	***2.05***	***2.25***	Earnings per sh A	***3.00***
.80	.83	.86	.89	.92	.94	.94	.95	.98	1.01	1.04	1.07	1.09	1.13	.87	1.54	***1.33***	***1.43***	Div'd Decl'd per sh B ■	***1.75***
2.55	2.58	2.81	2.42	2.08	2.13	1.23	1.57	1.53	1.78	2.22	3.50	2.94	2.95	3.63	3.99	***3.80***	***2.95***	Cap'l Spending per sh	***2.75***
8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	14.82	***15.55***	***16.40***	Book Value per sh C	***19.75***
84.09	89.53	90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	***106.81***	***106.81***	Common Shs Outst'g D	***106.81***
10.6	11.9	13.1	10.7	12.3	9.7	10.6	14.6	14.6	12.9	12.7	12.7	12.8	14.0	15.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	***13.5***
.68	.72	.77	.70	.82	.61	.61	.76	.83	.84	.65	.69	.73	.74	.83	.86	*Value Line*		Relative P/E Ratio	***.90***
7.7%	6.6%	5.8%	6.9%	7.2%	7.4%	6.5%	4.7%	4.8%	4.9%	5.0%	4.9%	4.9%	4.6%	3.1%	5.0%	*estimates*		Avg Ann'l Div'd Yield	***4.3%***

CAPITAL STRUCTURE as of 3/31/07
Total Debt $2979.2 mill. **Due in 5 Yrs** $1814.9 mill.
LT Debt $2324.3 mill. **LT Interest** $144.1 mill.
Incl. $558.6 mill. securitized bonds.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $18.1 mill.
Pension Assets-12/06 $1.03 bill. **Oblig.** $1.08 bill.
Pfd Stock $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cum., redeemable at $102.80-$103.625.
Common Stock 106,808,376 shs. as of 4/27/07
MARKET CAP: $3.9 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1776.2	1622.5	1851.4	2699.5	3191.8	2719.1	2914.1	2954.3	3243.1	3577.7	***3600***	***3825***	Revenues ($mill)	***4600***
144.6	141.0	146.5	181.0	179.1	181.3	188.0	190.4	198.1	208.7	***225***	***245***	Net Profit ($mill)	***315***
36.3%	34.3%	29.1%	41.6%	41.4%	35.8%	37.5%	38.5%	35.6%	37.8%	***40.0%***	***40.0%***	Income Tax Rate	***40.0%***
.8%	1.2%	1.5%	2.5%	2.8%	1.6%	2.4%	.5%	1.9%	3.3%	***3.0%***	***2.0%***	AFUDC % to Net Profit	***1.0%***
46.1%	45.5%	50.0%	59.4%	59.2%	60.9%	58.5%	58.6%	60.4%	59.2%	***56.0%***	***55.0%***	Long-Term Debt Ratio	***43.5%***
46.5%	50.1%	47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.7%	***42.5%***	***44.0%***	Common Equity Ratio	***55.5%***
2291.6	2099.5	3269.3	3409.8	3197.4	3433.7	3387.1	3585.3	3980.4	3986.3	***3895***	***3975***	Total Capital ($mill)	***3800***
2854.1	2270.7	2550.6	2523.6	2625.4	2847.6	3216.1	3425.0	3701.8	3945.3	***4135***	***4225***	Net Plant ($mill)	***4400***
8.3%	8.7%	6.1%	7.6%	8.1%	7.5%	7.8%	7.4%	7.1%	7.3%	***7.5%***	***8.0%***	Return on Total Cap'l	***9.5%***
11.7%	12.3%	9.0%	13.1%	13.7%	13.5%	13.4%	12.8%	12.6%	12.8%	***13.0%***	***13.5%***	Return on Shr. Equity	***14.5%***
12.3%	12.6%	9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	***13.5%***	***13.5%***	Return on Com Equity E	***15.0%***
3.7%	3.9%	2.4%	4.8%	5.0%	5.2%	5.1%	4.8%	4.6%	4.9%	***5.0%***	***5.0%***	Retained to Com Eq	***6.0%***
73%	71%	74%	64%	65%	63%	63%	64%	64%	63%	***64%***	***64%***	All Div'ds to Net Prof	***60%***

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+2.5	-1.9
Avg. Indust. Use (MWH)	1027	1022	1001
Avg. Indust. Revs. per KWH (¢)	7.90	8.20	8.40
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	4254	4682	4958
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (avg.)	+.4	+.7	+1.5
Fixed Charge Cov. (%)	287	266	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.0%	5.0%	6.0%
"Cash Flow"	3.5%	6.5%	5.5%
Earnings	4.5%	3.5%	8.5%
Dividends	2.5%	3.0%	7.0%
Book Value	3.5%	2.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	809.9	649.8	781.5	713.1	2954.3
2005	880.0	692.0	858.5	812.6	3243.1
2006	1034.8	784.6	956.3	802.0	3577.7
2007	984.4	***800***	***1000***	***815.6***	***3600***
2008	***1075***	***850***	***1050***	***850***	***3825***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.46	.35	.59	.35	1.76
2005	.43	.31	.72	.36	1.83
2006	.41	.43	.72	.38	1.93
2007	.45	***.44***	***.73***	***.43***	***2.05***
2008	***.50***	***.48***	***.80***	***.47***	***2.25***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.27	.27	.27	.27	1.08
2004	.278	.278	.278	.278	1.11
2005	.29	.29	.29	.29	1.16
2006	.303	.303	.303	.303	1.21
2007	.325	.325			

BUSINESS: NSTAR is a holding company for Boston Edison Company, which supplies electricity to an area of approx. 590 sq. mi. in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities, and Commonwealth Energy (acq'd 8/99), which provides electric and gas service in eastern Massachusetts. Serves 1.1 million electric, 300,000 gas customers. Electric revenue breakdown, '06: residential, 43%; commercial, 52%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 59% of revenues. '06 reported deprec. rate: 3.0%. Has 3,100 employees. Chairman, President & CEO: Thomas J. May. Inc.: Massachusetts. Address: 800 Boylston St., Boston, Massachusetts 02199-8003. Tel.: 617-424-2000. Internet: www.nstaronline.com.

We have trimmed our 2007 earnings estimate for NSTAR by a nickel a share, to $2.05. That's because first-quarter earnings of $0.45 a share, although up from $0.41 a share a year earlier (thanks in part to a return to normal weather patterns), were below our estimate of $0.49 a share. Profits should still wind up well above the 2006 tally, however. NSTAR is benefiting from a regulatory agreement in Massachusetts that took effect last May, and the utility is earning a healthy return (regulated by the Federal Energy Regulatory Commission) on a $220 million transmission project it has been building during the past couple of years. Our revised estimate for 2007 is still within the company's targeted range of $2.02-$2.12 a share. NSTAR shares are ranked 4 (Below Average) for year-ahead relative performance.

We estimate that earnings will climb 10% in 2008. The aforementioned regulatory agreement in Massachusetts runs through 2012 and provides annual incremental benefits for the company. Also, the costs of programs to improve customer service and accelerate staffing to address the effects of an aging workforce should be limited to 2007.

There will probably be four common dividend declarations in 2007. Ordinarily, this wouldn't be worth mentioning. But the dividend declaration that was originally scheduled for the fourth quarter of 2005 was postponed until the first quarter of 2006. Accordingly, there were just three declarations in 2005 and five last year. That's why there are unusual fluctuations in the "dividends declared" line in the statistical array above, despite the fact that NSTAR has established a record of dividend growth dating back to the late 1990s. Even with the change in the declaration dates, common stockholders still received their dividend payments on schedule.

This stock is suitable for conservative, income-oriented investors. It is ranked 1 (Highest) for Safety. Its yield is a bit above the utility average. In addition, NSTAR offers better 3- to 5-year earnings and dividend growth potential than most utilities, so total-return potential through 2010-2012 is above the industry average as well.

Paul E. Debbas, CFA *June 1, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '04,'05, & '06 EPS don't add to full-year total due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $2.5 bill., $23.52/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '06: 13.3%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

PUGET ENERGY, INC. NYSE-PSD

RECENT PRICE **26.06** | P/E RATIO **17.1** (Trailing: 18.1; Median: 16.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **3.8%** | VALUE LINE

High:	26.0	30.2	30.3	28.4	28.0	27.8	23.6	24.4	24.8	24.6	25.9	26.9
Low:	22.1	23.5	24.1	18.6	19.1	18.5	16.6	18.1	20.5	20.2	20.1	24.0

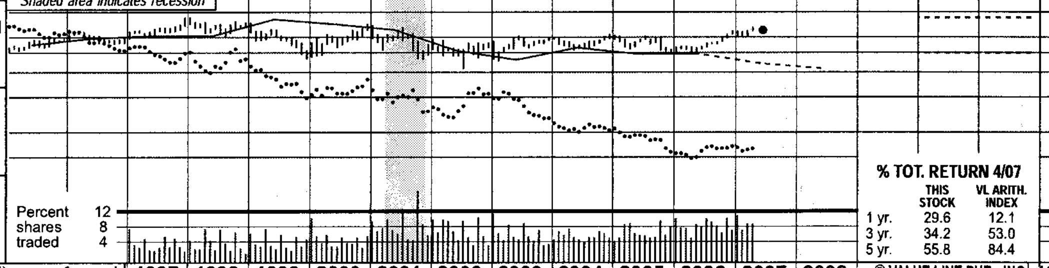
TIMELINESS 3 Lowered 2/16/07

SAFETY 3 Lowered 10/19/01

TECHNICAL 3 Raised 4/6/07

BETA .85 (1.00 = Market)

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	5
to Sell	0	0	0	0	0	2	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	97	106	114
to Sell	89	64	75
Hld's(000)	72569	72824	71969

Percent shares traded 12 8 4

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.6	12.1
3 yr.	34.2	53.0
5 yr.	55.8	84.4

Puget Sound Energy (PSE) was formed through the merger of Puget Sound Power & Light and Washington Energy effective February 11, 1997. Shareholders of Washington Energy received .86 of a share of Puget Sound P&L stock for each Washington Energy share. PSE changed its name to Puget Energy when it formed a holding company at the start of 2001.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
19.83	22.56	24.34	40.06	38.77	25.55	25.15	25.72	22.24	24.93	*26.05*	*27.20*	Revenues per sh	*30.25*
3.19	3.81	3.98	4.52	3.78	3.80	3.90	4.02	3.56	3.96	*4.35*	*4.55*	"Cash Flow" per sh	*5.25*
1.28	1.85	1.91	2.16	1.22	1.24	1.22	1.32	1.42	1.44	*1.60*	*1.65*	Earnings per sh A	*2.00*
1.84	1.84	1.84	1.84	1.84	1.21	1.00	1.00	1.00	1.00	*1.00*	*1.00*	Div'd Decl'd per sh B ■ †	*1.20*
3.11	4.05	3.96	3.56	3.11	2.67	3.09	3.55	5.28	6.74	*4.55*	*5.30*	Cap'l Spending per sh	*5.25*
16.06	16.00	16.24	16.61	15.66	16.27	16.71	16.24	17.52	18.15	*18.80*	*19.45*	Book Value per sh C	*22.00*
84.56	84.56	84.92	85.90	87.02	93.64	99.07	99.87	115.70	116.58	*117.00*	*117.75*	Common Shs Outst'g D	*124.25*
20.4	14.6	12.3	10.8	19.1	17.1	18.1	17.1	15.8	15.4	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.0*
1.18	.76	.70	.70	.98	.93	1.03	.90	.84	.83	*estimates*		Relative P/E Ratio	*.85*
7.1%	6.8%	7.8%	7.9%	7.9%	5.7%	4.5%	4.4%	4.5%	4.5%			Avg Ann'l Div'd Yield	*4.6%*
1676.9	1907.3	2066.6	3441.7	3374.0	2392.3	2491.5	2568.8	2573.2	2905.7	*3050*	*3200*	Revenues ($mill)	*3750*
125.7	169.6	173.3	193.8	113.6	117.9	122.6	131.7	146.4	167.3	*185*	*195*	Net Profit ($mill)	*255*
33.2%	40.0%	37.8%	39.5%	40.6%	32.7%	36.4%	37.7%	37.0%	35.6%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
4.1%	4.5%	6.1%	6.2%	6.3%	3.9%	4.0%	5.2%	8.4%	11.1%	*5.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
46.4%	47.6%	52.6%	59.5%	62.2%	60.1%	57.6%	60.5%	54.4%	55.5%	*57.0%*	*56.5%*	Long-Term Debt Ratio	*51.5%*
44.6%	43.7%	40.7%	37.4%	34.9%	37.4%	42.4%	39.4%	45.6%	44.4%	*43.0%*	*43.5%*	Common Equity Ratio	*48.5%*
3043.4	3095.7	3387.9	3815.6	3900.4	4076.7	3906.7	4116.9	4450.0	4764.0	*5120*	*5250*	Total Capital ($mill)	*5625*
3250.5	3430.9	3750.9	3838.4	3888.0	3916.2	4080.2	4228.4	4630.9	5181.0	*5510*	*5795*	Net Plant ($mill)	*6750*
5.6%	7.1%	7.1%	7.0%	5.2%	4.9%	5.2%	5.3%	5.2%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.7%	10.5%	10.8%	12.5%	7.7%	7.2%	7.4%	8.1%	7.2%	7.9%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.5%*
7.9%	11.6%	11.8%	13.0%	7.7%	7.2%	7.0%	8.1%	7.2%	7.9%	*8.5%*	*8.5%*	Return on Com Equity E	*9.5%*
NMF	.1%	1.0%	3.6%	NMF	1.3%	2.1%	2.8%	2.9%	3.0%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
NMF	99%	92%	74%	125%	83%	72%	66%	60%	62%	*63%*	*61%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $3099.2 mill. **Due in 5 Yrs** $1282.6 mill.
LT Debt $2646.1 mill. **LT Interest** $177.3 mill.
Incl. $37.8 mill. tax-deductible preferred securities with interest rate of 8.231%.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $13.8 mill.
Pension Assets-12/06 $532.6 mill. **Oblig.** $469.0 mill.
Pfd Stock $1.9 mill. **Pfd Div'd** $.1 mill.
4,311 shs. 4.70%, 14,583 shs. 4.84%, $100 par, callable $101 to $102. All shares cumulative.
Common Stock 116,723,205 shs. as of 2/21/07
MARKET CAP: $3.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+3.0	+3.1
Avg. Indust. Use (MWH)	340	350	370
Avg. Indust. Revs. per KWH (¢)	6.56	6.92	7.53
Capacity at Yearend (Mw)	4351	4360	4456
Peak Load, Winter (Mw)	4351	4360	4456
Annual Load Factor (%)	53.5	57.4	53.5
% Change Customers (yr-end)	+2.4	+1.6	+2.1
Fixed Charge Cov. (%)	214	224	230

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.5%	-6.5%	*3.5%*
"Cash Flow"	1.0%	-1.0%	*5.5%*
Earnings	-2.5%	-4.5%	*6.0%*
Dividends	-6.0%	-11.5%	*3.0%*
Book Value	-.5%	1.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	743.5	515.9	515.0	794.4	2568.8
2005	741.6	510.1	490.4	831.1	2573.2
2006	877.7	574.2	519.5	934.3	2905.7
2007	1003.9	*600*	*575*	*871.1*	*3050*
2008	*1050*	*625*	*600*	*925*	*3200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.67	d.07	.11	.61	1.32
2005	.72	.12	.06	.52	1.42
2006	.63	.18	.14	.49	1.44
2007	.68	*.20*	*.15*	*.57*	*1.60*
2008	*.70*	*.20*	*.15*	*.60*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.25	.25	.25	.25	1.00
2004	.25	.25	.25	.25	1.00
2005	.25	.25	.25	.25	1.00
2006	.25	.25	.25	.25	1.00
2007	.25				

BUSINESS: Puget Energy, Inc. is a holding company for Puget Sound Energy (PSE), which sells electricity and gas to 1.4 million customers in a 6,000-sq.-mi. region in western Washington. Merged with Washington Energy 2/97. Discontinued InfrastruX (utility construction services) in '05. Electric revenue breakdown, '06: residential, 45%; commercial, 40%; industrial, 6%; other, 9%. Generating sources, '06: coal, 20%; hydro, 4%; oil & gas, 3%; wind, 1%; purchased, 72%. Fuel costs: 60% of revenues. '06 reported deprec. rates: 2.9% electric, 3.3% gas. Has 2,400 employees. Chairman: Douglas P. Beighle. President & CEO: Stephen P. Reynolds. Inc.: Washington. Address: P.O. Box 97034, Bellevue, Washington 98009-9734. Tel.: 425-454-6363. Internet: www.pugetenergy.com.

Puget Energy's utility subsidiary has filed a power-cost-only rate case to recover the cost of a power plant it acquired. Puget Sound Energy paid $120 million for the 277-megawatt Goldendale gas-fired plant. The advantage of a power-cost-only case, versus a full-blown rate case, is a streamlined regulatory process with an order in five months, not 11. The utility is seeking a $65 million (3.7%) rate hike to recover the cost of Goldendale. The decision of the Washington commission is due in time for new rates to take effect at the start of September.

Meeting the utility's power needs is a key challenge. Historically, PSE has purchased most of its power, but this option is less attractive since purchased-power costs became increasingly volatile several years ago. But options for adding generating capacity in Washington are limited. Coal-fired plants raise too many environmental concerns, and PSE, without any ownership in nuclear power, isn't about to consider such a facility. So, gas and wind are it. Goldendale is the second gas-fired plant that PSE has purchased in recent years, and the utility built 580 megawatts of wind capacity in 2005 and 2006. Gas is costly, and wind plants run less than half the time, so there is no "ideal" option for the company.

We expect a significant earnings increase in 2007, followed by a more modest rise in 2008. This year, the fourth-quarter comparison should be relatively easy, since PSE swallowed $10.9 million of storm-related expenses in the fourth period of 2006. (The utility deferred $92.3 million of these costs for future recovery.) We have trimmed our 2007 estimate by a nickel a share, but it is still within the company's targeted range of $1.50-$1.65. We figure that growth in demand will produce an earnings uptick in 2008. We aren't estimating a dividend increase next year, but we don't rule one out, either.

This stock offers a decent dividend yield. But, even with our projection of earnings and dividend growth 3 to 5 years out, with the issue trading well within our 2010-2012 Target Price Range, total-return potential over that time is unimpressive.

Paul E. Debbas, CFA *May 11, 2007*

(A) Diluted EPS. Excl. nonrec. gain (losses): '99, 15¢; '01, (8¢) net; '04, (77¢); gains (loss) on discont. ops.: '97, (3¢); '05, 9¢; '06, 45¢. Incl. merger costs: '97, 43¢. Next earnings report due late July. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '06: $283.2 mill., $2.43/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '07: 10.4%; earned on avg. com. eq., '06: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	15
Earnings Predictability	50

UIL HOLDINGS NYSE-UIL

RECENT PRICE	33.50	P/E RATIO	18.1 (Trailing: 17.4) (Median: 15.0)	RELATIVE P/E RATIO	0.94	DIV'D YLD	5.2%	VALUE LINE

TIMELINESS 4 Lowered 3/2/07

SAFETY 3 Lowered 12/6/02

TECHNICAL 4 Lowered 5/11/07

BETA .95 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	24.0	27.6	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0
Low:	18.7	14.2	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	33.2

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

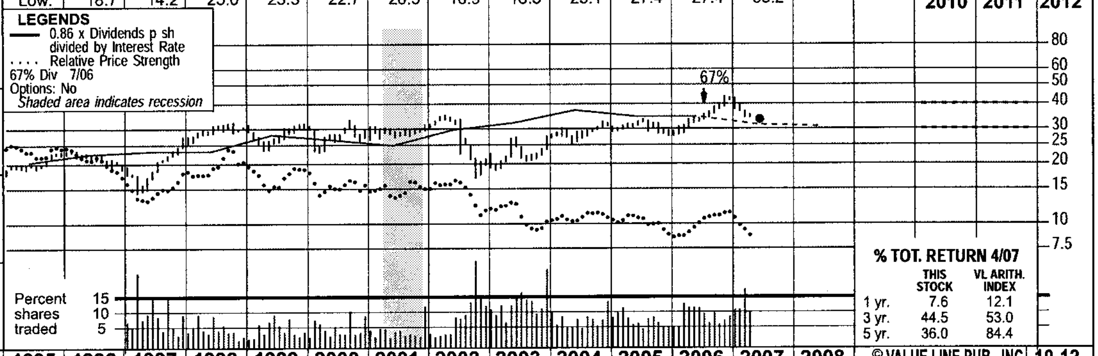
	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	0	0	3	0	0	0	0
to Sell	1	2	0	0	3	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	62	57	82
to Sell	40	54	34
Hld's(000)	11519	11770	12105



% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.6	12.1
3 yr.	44.5	53.0
5 yr.	36.0	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
29.00	28.53	27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	**41.25**	**44.90**	Revenues per sh	**51.90**
4.79	4.90	4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	**5.00**	**5.85**	"Cash Flow" per sh	**7.40**
1.93	1.90	1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	**1.85**	**1.95**	Earnings per sh A	**2.15**
1.46	1.54	1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	**1.73**	**1.73**	Div'd Decl'd per sh B ■	**1.73**
2.72	2.84	4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	**10.35**	**5.50**	Cap'l Spending per sh	**3.75**
17.30	18.07	18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	**18.70**	**19.05**	Book Value per sh C	**19.95**
23.22	23.39	23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	**25.20**	**25.40**	Common Shs Outst'g E	**26.60**
10.6	11.9	13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	**16.5**
.68	.72	.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	*Value Line*		Relative P/E Ratio	**1.10**
7.2%	6.8%	6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	*estimates*		Avg Ann'l Div'd Yield	**4.9%**

CAPITAL STRUCTURE as of 12/31/06
Total Debt $486.9 mill. **Due in 5 Yrs.** $291.4 mill.
LT Debt $408.6 mill. **LT Interest** $21.5 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized: Ann. rentals $13.4 mill.

Pension Assets-12/06 $317 mill. **Oblig.** $362 mill.

Pfd Stock None

Common Stock 24,856,043 shs.

MARKET CAP: $825 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
710.3	686.2	680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	**1040**	**1140**	Revenues ($mill)	**1380**
45.8	42.2	52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	**46.0**	**49.0**	Net Profit ($mill)	**57.0**
47.4%	56.0%	56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	**31.0%**	**31.0%**	Income Tax Rate	**31.0%**
3.5%	1.1%	4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	**6.0%**	**6.0%**	AFUDC % to Net Profit	**3.0%**
57.3%	57.7%	50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	**49.5%**	**50.0%**	Long-Term Debt Ratio	**48.5%**
38.0%	37.7%	44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	**50.5%**	**50.0%**	Common Equity Ratio	**51.5%**
1154.8	1180.8	1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	**930**	**965**	Total Capital ($mill)	**1030**
1273.6	1226.4	521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	**830**	**870**	Net Plant ($mill)	**810**
6.7%	5.4%	7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	**6.0%**	**6.5%**	Return on Total Cap'l	**7.0%**
9.3%	8.4%	10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	**9.5%**	**10.0%**	Return on Shr. Equity	**10.5%**
10.4%	9.4%	11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	**9.5%**	**10.0%**	Return on Com Equity D	**10.5%**
1.2%	.4%	2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	**.5%**	**1.0%**	Retained to Com Eq	**2.0%**
89%	96%	78%	68%	68%	93%	NMF	112%	NMF	117%	**93%**	**89%**	All Div'ds to Net Prof	**80%**

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.3	+2.6	-3.1
Avg. Indust. Use (MWH)	639	665	657
Avg. Indust. Revs. per KWH (¢)	9.13	9.70	10.2
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.1	Nil	Nil
Fixed Charge Cov. (%)	375	263	323

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.0%	3.0%	3.0%
"Cash Flow"	-1.0%	-5.0%	9.0%
Earnings	-2.5%	-8.5%	5.5%
Dividends	--	--	Nil
Book Value	1.5%	1.0%	-1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	249.4	260.7	323.4	267.8	1101.3
2005	278.5	279.9	369.4	285.3	1213.1
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	**240**	**300**	**225.4**	**1040**
2008	**300**	**265**	**325**	**250**	**1140**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.24	.43	.68	.19	1.54
2005	.13	.14	.77	.26	1.30
2006	.15	.42	1.21	.08	1.86
2007	.22	**.45**	**.93**	**.25**	**1.85**
2008	**.22**	**.48**	**.98**	**.27**	**1.95**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.432	.432	.432	.432	1.73
2004	.432	.432	.432	.432	1.73
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432			

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 320,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 46%; commer, 41%; indust, 11%; other, 2%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. 2004, sold American Payment Systems. 2006, sold Xcelecom. Fuel costs: 49% of revenues; labor costs, 13%. '06 deprec. rate: 3.8%. Has 920 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Tel.: 203-499-2394. Internet: www.uil.com.

UIL Holdings and Connecticut L&P are building a 345-kilovolt transmission line to strengthen the grid. The 69-mile line, which will run between Middletown and Norwalk, will increase the inflow of power from out of state. The cost of the project rose from an original estimate of $600 million to $1.3 billion because of an agreement to construct 24 miles underground. UIL will have a 20% stake in the line, which is targeted to begin operations in the summer of 2009. Regulation permits the company to recover prudently incurred costs as work progresses. The balance will be recovered through rate requests. In the early stages, UIL will finance its share of the cost internally, later with short-term and long-term debt. The line will not only supply power to the two owners but will generate income by serving other New England utilities.

The company is upgrading its aging infrastructure. A majority of operating assets were installed in the 1960s and 1970s. Their average useful lives range from 35 to 50 years. Some 81% of substations are now more than 30 years old, and their reliability is diminishing. To insure that equipment exceeds acceptable standards, UIL plans capital expenditures of $1.75 billion over the next 10 years. Regulation which permits ongoing recovery of 50% of prudently incurred costs will ease the financial burden somewhat. The balance must be recouped through rates.

Earnings may only mark time this year. Pluses include higher retail energy sales, improved pricing, and an electric rate increase of $4.3 million. But an IRS letter authorizing a one-time tax credit of $0.26 a share taken in the third quarter of 2006 will offset these positives. For now, we estimate current-year earnings of $1.85 a share. Higher rates of $4.3 million suggest modest improvement in 2008. The stock is untimely.

The share price has declined about 15% since our report six months ago. That's attributable, in our opinion, to additional losses associated with Xcelecom as a result of a further review. (Our earnings presentation excludes these charges because of their nonrecurring nature.) At the stock's recent quote, UIL is an average long-term utility holding.

Arthur H. Medalie *June 1, 2007*

(A) EPS basic. Excl. nonrecur. gains (losses): '91, 27¢; '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, net 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due late July. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '06: 77¢/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '06: 9.75%. Earned on average common equity in '06: 9.0%. Regul. Clim.: Below Average. (E) In millions.

Company's Financial Strength	B+
Stock's Price Stability	75
Price Growth Persistence	70
Earnings Predictability	60

ATTACHMENT B

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

CH ENERGY GRP HLDG (NYSE)

Scottrade

CHG	44.10	▾-0.46	(-1.03%)	Vol. 20,700	13:56 ET

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

General Information

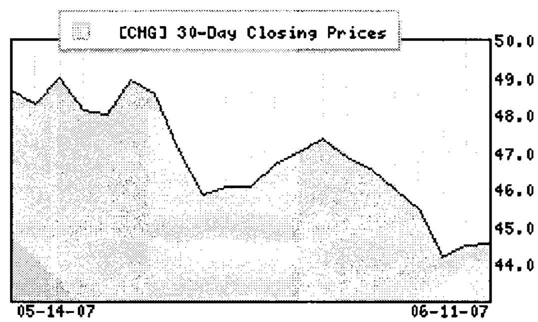
CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	07/24/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	44.56
52 Week High	53.76
52 Week Low	45.18
Beta	0.48
20 Day Moving Average	64,250.00
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.25	4 Week	-6.01
12 Week	-3.21	12 Week	-9.67

YTD	-13.18	YTD	-15.33
Share Information		**Dividend Information**	
Shares Outstanding (millions)	15.76	Dividend Yield	4.71%
		Annual Dividend	$2.16
Market Capitalization (millions)	722.53	Payout Ratio	0.73
Short Ratio	23.20	Change in Payout Ratio	-0.10
Last Split Date	N/A	Last Dividend Payout / Amount	04/05/2007 / $0.54

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	N/A
Current Year EPS Consensus Estimate	2.67	30 Days Ago	N/A
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	N/A
Next EPS Report Date	07/24/2007	90 Days Ago	N/A

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	17.14	vs. Previous Year	18.10%	vs. Previous Year	8.24%
Trailing 12 Months:	15.54	vs. Previous Quarter	120.97%	vs. Previous Quarter:	54.36%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.41	03/31/07	9.03	03/31/07	3.27
Price/Cash Flow	9.17	12/31/06	8.42	12/31/06	3.08
Price / Sales	0.71	09/30/06	8.83	09/30/06	3.26
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.68	03/31/07	1.55	03/31/07	4.56
12/31/06	1.39	12/31/06	1.25	12/31/06	4.34
09/30/06	1.36	09/30/06	1.19	09/30/06	4.33
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	6.98	03/31/07	6.98	03/31/07	33.41
12/31/06	6.81	12/31/06	6.81	12/31/06	32.54
09/30/06	7.02	09/30/06	7.02	09/30/06	32.47
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	25.17	03/31/07	0.70	03/31/07	41.42
12/31/06	22.59	12/31/06	0.66	12/31/06	38.86

09/30/06	24.35	09/30/06	0.61	09/30/06	36.96

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

CLECO CP(HLDG CO) (NYSE)

CNL	25.20	▼-0.05	(-0.20%)	Vol. 98,500	14:01 ET

Cleco Corporation holds investments in several subsidiaries, including Utility Group, Cleco Midstream Resources LLC and Utility Construction & Technology Solutions LLC. Utility Group, incorporated on January 2, 1935 under the laws of the State of Louisiana, contains the LPSC jurisdictional generation, transmission and distribution electric utility operations serving the Company's traditional retail and wholesale customers. Utility Group serves customers in communities and rural areas in the State of Louisiana.

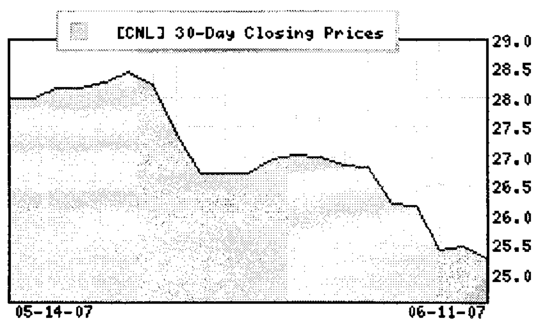
General Information

CLECO CORP
2030 Donahue Ferry Road
Pineville, LA 71360-5226
Phone: 318 484-7400
Fax: 318 484-7465
Web: www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.25
52 Week High	29.01
52 Week Low	21.64
Beta	1.39
20 Day Moving Average	505,829.25
Target Price Consensus	27.5



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	-7.89	4 Week	-8.63
12 Week	1.98	12 Week	-4.83

YTD	5.91	YTD	4.44
Share Information		**Dividend Information**	
Shares Outstanding (millions)	57.68	Dividend Yield	3.37%
		Annual Dividend	$0.90
Market Capitalization (millions)	1,541.21	Payout Ratio	0.72
Short Ratio	8.53	Change in Payout Ratio	0.00
Last Split Date	05/22/2001	Last Dividend Payout / Amount	04/26/2007 / $0.44

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.26	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.30	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	12.00	60 Days Ago	2.75
Next EPS Report Date	08/09/2007	90 Days Ago	2.75

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	20.55	vs. Previous Year	-39.13%	vs. Previous Year	0.15%
Trailing 12 Months:	21.38	vs. Previous Quarter	-22.22%	vs. Previous Quarter:	-3.64%
PEG Ratio	1.71				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.75	03/31/07	8.47	03/31/07	3.53
Price/Cash Flow	20.57	12/31/06	9.47	12/31/06	3.85
Price / Sales	1.54	09/30/06	8.83	09/30/06	2.95
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.20	03/31/07	0.94	03/31/07	7.10
12/31/06	7.77	12/31/06	1.18	12/31/06	7.46
09/30/06	1.45	09/30/06	1.24	09/30/06	6.30
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	7.16	03/31/07	7.16	03/31/07	15.48
12/31/06	-	12/31/06	-	12/31/06	15.24
09/30/06	27.75	09/30/06	27.75	09/30/06	15.59
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-0.37	03/31/07	0.69	03/31/07	40.93
12/31/06	0.00	12/31/06	0.11	12/31/06	10.04

09/30/06	11.67	09/30/06	0.66	09/30/06	39.34

Zacks.com Quotes and Research

HAWAIIAN ELEC INDS (NYSE)

HE	23.44	▼-0.11	(-0.47%)	Vol. 132,400	14:08 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

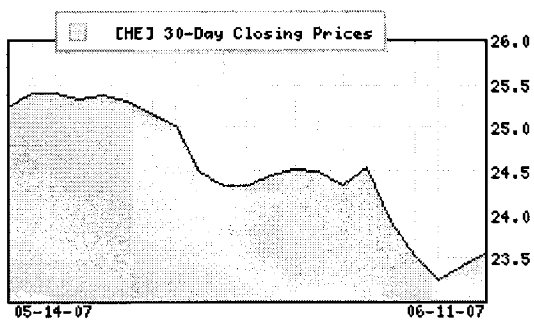
General Information

HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/07/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	23.55
52 Week High	28.93
52 Week Low	24.50
Beta	0.48
20 Day Moving Average	342,402.56
Target Price Consensus	25.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.30	4 Week	-8.05
12 Week	-6.38	12 Week	-12.63
YTD	-9.76	YTD	-12.97

Share Information		Dividend Information	
Shares Outstanding (millions)	81.47	Dividend Yield	5.06%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,996.04	Payout Ratio	1.13
Short Ratio	23.75	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	02/22/2007 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.33	Current (1=Strong Buy, 5=Strong Sell)	3.50
Current Year EPS Consensus Estimate	1.26	30 Days Ago	3.33
Estimated Long-Term EPS Growth Rate	4.90	60 Days Ago	3.33
Next EPS Report Date	08/07/2007	90 Days Ago	3.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.47	vs. Previous Year	-57.50%	vs. Previous Year	-3.64%
Trailing 12 Months:	22.27	vs. Previous Quarter	-15.00%	vs. Previous Quarter:	-8.74%
PEG Ratio	3.99				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.82	03/31/07	7.71	03/31/07	0.90
Price/Cash Flow	7.67	12/31/06	9.10	12/31/06	1.09
Price / Sales	0.82	09/30/06	10.63	09/30/06	1.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.66	03/31/07	0.66	03/31/07	3.66
12/31/06	0.26	12/31/06	0.26	12/31/06	4.39
09/30/06	0.25	09/30/06	0.25	09/30/06	5.22
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	5.25	03/31/07	5.25	03/31/07	13.46
12/31/06	6.95	12/31/06	6.95	12/31/06	13.46
09/30/06	8.28	09/30/06	8.28	09/30/06	15.23
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	1.12	03/31/07	53.46
12/31/06	-	12/31/06	1.03	12/31/06	50.08
09/30/06	-	09/30/06	0.92	09/30/06	48.53

Zacks.com Quotes and Research

MGE ENERGY INC. (NASDAQ)

MGEE	31.74	▼-0.66	(-2.04%)	Vol. 94,298	16:00 ET

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

General Information

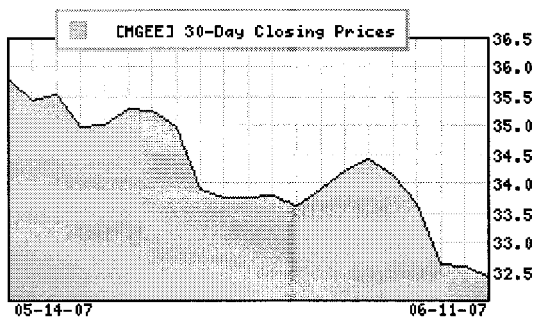
MGE ENERGY INC
133 South Blair St
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mge.com
Email: investor@mgeenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	N/A

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.40
52 Week High	37.00
52 Week Low	29.28
Beta	0.54
20 Day Moving Average	56,889.80
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-8.38	4 Week	-9.11
12 Week	1.47	12 Week	-5.31

YTD	-7.33	YTD	-10.86

Share Information		**Dividend Information**	
Shares Outstanding (millions)	20.99	Dividend Yield	4.11%
		Annual Dividend	$1.39
Market Capitalization (millions)	711.66	Payout Ratio	0.67
Short Ratio	23.77	Change in Payout Ratio	0.00
Last Split Date	02/21/1996	Last Dividend Payout / Amount	02/27/2007 / $0.35

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	N/A
Current Year EPS Consensus Estimate	N/A	30 Days Ago	N/A
Estimated Long-Term EPS Growth Rate	N/A	60 Days Ago	N/A
Next EPS Report Date	N/A	90 Days Ago	N/A

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	-	vs. Previous Year	5.36%	vs. Previous Year	5.86%
Trailing 12 Months:	16.22	vs. Previous Quarter	9.26%	vs. Previous Quarter:	21.12%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.02	03/31/07	11.81	03/31/07	4.61
Price/Cash Flow	11.21	12/31/06	12.01	12/31/06	4.65
Price / Sales	1.38	09/30/06	11.34	09/30/06	4.36
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.99	03/31/07	0.75	03/31/07	8.36
12/31/06	-	12/31/06	-	12/31/06	8.36
09/30/06	0.80	09/30/06	0.46	09/30/06	7.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	18.39
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	12.13	09/30/06	12.13	09/30/06	17.54
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	0.61	03/31/07	38.07
12/31/06	-	12/31/06	-	12/31/06	-

09/30/06	6.23	09/30/06	0.58	09/30/06	36.51

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

NORTHEAST UTIL (NYSE)				
NU	28.14	▾-0.36	(-1.26%)	Vol. 935,200	16:01 ET

Northeast Utilities is the parent company of the Northeast Utilitiessystem. The Northeast Utilities system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through three of the company's wholly owned subsidiaries: The Connecticut Light and Power Company; Public Service Company of New Hampshire; and Western Massachusetts Electric Company. It also provides service to a limited number of customers through another wholly owned subsidiary, Holyoke Water Power Company.

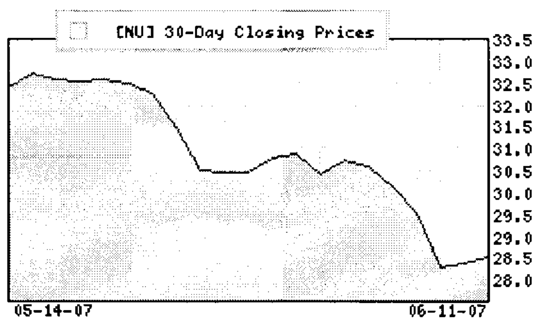
General Information

NORTHEAST UTIL
One Federal Street
Building 111-4
Springfield, MA 01105
Phone: 413 785-5871
Fax: 413 665-3652
Web: www.nu.com
Email: psnhreq@psnh.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.50
52 Week High	33.53
52 Week Low	19.36
Beta	0.42
20 Day Moving Average	890,615.88
Target Price Consensus	30.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.97	4 Week	-8.70

12 Week	5.03	12 Week	-1.99
YTD	8.31	YTD	7.76

Share Information		**Dividend Information**	
Shares Outstanding (millions)	154.29	Dividend Yield	2.46%
		Annual Dividend	$0.75
Market Capitalization (millions)	4,705.69	Payout Ratio	0.65
Short Ratio	4.20	Change in Payout Ratio	0.08
Last Split Date	N/A	Last Dividend Payout / Amount	02/27/2007 / $0.19

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.25	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.43	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	13.00	60 Days Ago	3.00
Next EPS Report Date	08/09/2007	90 Days Ago	2.60

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	21.33	vs. Previous Year	44.12%	vs. Previous Year	-20.63%
Trailing 12 Months:	26.52	vs. Previous Quarter	36.11%	vs. Previous Quarter:	14.91%
PEG Ratio	1.64				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.68	03/31/07	6.75	03/31/07	1.56
Price/Cash Flow	7.32	12/31/06	6.12	12/31/06	1.32
Price / Sales	0.73	09/30/06	5.91	09/30/06	1.20
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.80	03/31/07	1.63	03/31/07	2.73
12/31/06	1.27	12/31/06	1.14	12/31/06	2.22
09/30/06	1.36	09/30/06	1.25	09/30/06	1.95
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	3.07	03/31/07	3.07	03/31/07	18.26
12/31/06	0.73	12/31/06	0.73	12/31/06	18.17
09/30/06	-0.22	09/30/06	-0.22	09/30/06	16.08
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	26.94	03/31/07	1.54	03/31/07	61.31

12/31/06	29.99	12/31/06	1.48	12/31/06	59.66
09/30/06	30.29	09/30/06	1.69	09/30/06	63.51

Zacks.com Quotes and Research

NSTAR (NYSE)					Scottrade
NST	32.67	▼-0.43	(-1.30%)	Vol. 315,400	16:03 ET

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

General Information

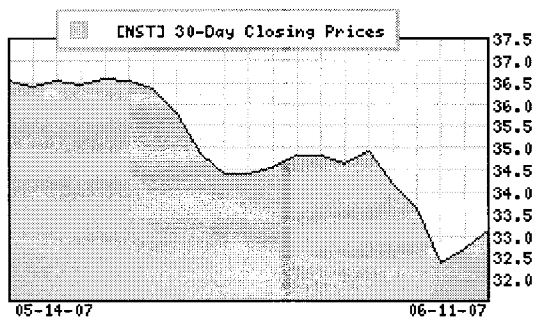
NSTAR
800 Boylston Street
Boston, MA 02199
Phone: 617 424-2000
Fax: 617 424-4032
Web: www.nstaronline.com
Email: ir@nstar.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	07/26/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.10
52 Week High	37.27
52 Week Low	27.15
Beta	0.51
20 Day Moving Average	296,505.00
Target Price Consensus	37



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.39	4 Week	-7.14
12 Week	1.99	12 Week	-4.82

YTD	1.54	YTD	-0.81
Share Information		**Dividend Information**	
Shares Outstanding (millions)	106.81	Dividend Yield	3.73%
		Annual Dividend	$1.30
Market Capitalization (millions)	3,726.53	Payout Ratio	0.66
Short Ratio	8.84	Change in Payout Ratio	0.01
Last Split Date	06/06/2005	Last Dividend Payout / Amount	04/05/2007 / $0.32

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.44	Current (1=Strong Buy, 5=Strong Sell)	2.29
Current Year EPS Consensus Estimate	2.09	30 Days Ago	2.29
Estimated Long-Term EPS Growth Rate	6.30	60 Days Ago	2.00
Next EPS Report Date	07/26/2007	90 Days Ago	2.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.67	vs. Previous Year	9.76%	vs. Previous Year	-4.87%
Trailing 12 Months:	17.62	vs. Previous Quarter	18.42%	vs. Previous Quarter:	22.73%
PEG Ratio	2.67				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.35	03/31/07	13.26	03/31/07	2.74
Price/Cash Flow	6.53	12/31/06	13.29	12/31/06	2.69
Price / Sales	1.06	09/30/06	13.28	09/30/06	2.68
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.76	03/31/07	0.72	03/31/07	5.97
12/31/06	0.77	12/31/06	0.67	12/31/06	5.78
09/30/06	0.78	09/30/06	0.68	09/30/06	5.72
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	9.38	03/31/07	9.38	03/31/07	15.40
12/31/06	9.12	12/31/06	9.12	12/31/06	14.82
09/30/06	7.03	09/30/06	7.03	09/30/06	14.82
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	19.26	03/31/07	1.05	03/31/07	51.15
12/31/06	19.45	12/31/06	1.49	12/31/06	59.87

09/30/06	20.86	09/30/06	1.09	09/30/06	52.74

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

PUGET ENERGY HOLDING (NYSE)

Scottrade

PSD 24.00 ▼-0.33 (-1.36%) Vol. 627,800 16:04 ET

Puget Sound Energy, Incorporated is an investor-owned public utility that furnishes electric and gas service. The company conducts its business principally in the Puget Sound region of Washington state. PSE is on the forefront of the future. Innovative programs such as the PSE EnergyTracker are helping to make them the best energy distribution company anywhere, bar none. It's part of an ongoing promise: to offer their customers, community and shareholders unparalleled value in the 21st century.

General Information

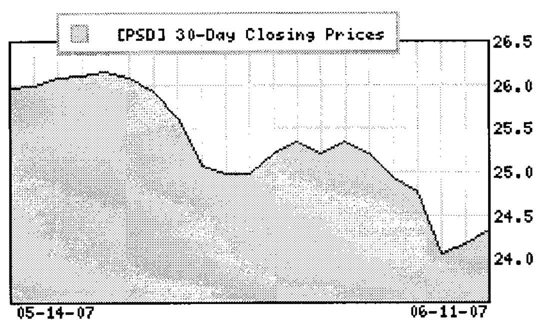
PUGET ENERGY
10885 N.E. 4th Street
Suite 1200
Bellevue, WA 98004-5591
Phone: 425 454-6363
Fax: 425 462-3300
Web: www.pse.com
Email: investor@pse.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.33
52 Week High	26.80
52 Week Low	20.47
Beta	0.38
20 Day Moving Average	479,450.00
Target Price Consensus	27.2



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.54	4 Week	-6.29

12 Week	1.66	12 Week	-5.13
YTD	-1.10	YTD	-3.96

Share Information		**Dividend Information**	
Shares Outstanding (millions)	116.72	Dividend Yield	3.99%
		Annual Dividend	$1.00
Market Capitalization (millions)	2,927.41	Payout Ratio	0.67
Short Ratio	4.76	Change in Payout Ratio	-0.09
Last Split Date	N/A	Last Dividend Payout / Amount	04/18/2007 / $0.25

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.26	Current (1=Strong Buy, 5=Strong Sell)	2.60
Current Year EPS Consensus Estimate	1.61	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.60
Next EPS Report Date	08/09/2007	90 Days Ago	3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.54	vs. Previous Year	6.25%	vs. Previous Year	14.37%
Trailing 12 Months:	16.83	vs. Previous Quarter	38.78%	vs. Previous Quarter:	7.45%
PEG Ratio	3.88				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.38	03/31/07	8.15	03/31/07	2.57
Price/Cash Flow	6.80	12/31/06	7.90	12/31/06	2.49
Price / Sales	0.97	09/30/06	8.03	09/30/06	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	-	03/31/07	-	03/31/07	5.70
12/31/06	0.77	12/31/06	0.62	12/31/06	5.76
09/30/06	-	09/30/06	-	09/30/06	5.94
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	8.94	12/31/06	8.94	12/31/06	18.18
09/30/06	-	09/30/06	-	09/30/06	-
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	-	03/31/07	-

12/31/06	14.61	12/31/06	1.23	12/31/06	55.54
09/30/06	-	09/30/06	-	09/30/06	-

Zacks.com Quotes and Research

UIL HLDGS CP (NYSE)

UIL	32.11	▼-0.45	(-1.38%)	Vol. 172,800	16:02 ET

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

General Information

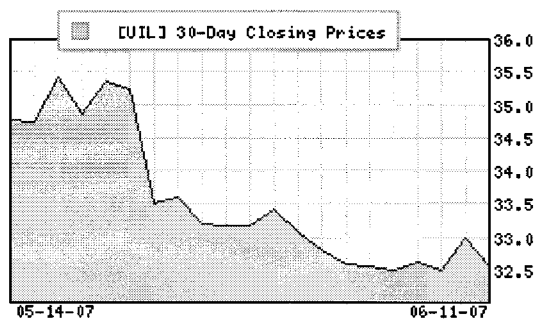
UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203 499-2000
Fax: 203 499-2414
Web: www.uil.com
Email: Susan.Allen@uinet.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/08/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.56
52 Week High	43.44
52 Week Low	32.43
Beta	0.84
20 Day Moving Average	183,370.00
Target Price Consensus	37



% Price Change

4 Week	-5.84
12 Week	-8.87
YTD	-21.31

% Price Change Relative to S&P 500

4 Week	-6.60
12 Week	-14.95
YTD	-21.94

Share Information		Dividend Information	
Shares Outstanding (millions)	25.06	Dividend Yield	5.20%
		Annual Dividend	$1.73
Market Capitalization (millions)	831.93	Payout Ratio	1.17
Short Ratio	8.37	Change in Payout Ratio	0.00
Last Split Date	07/05/2006	Last Dividend Payout / Amount	03/02/2007 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.41	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.99	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	08/08/2007	90 Days Ago	3.00

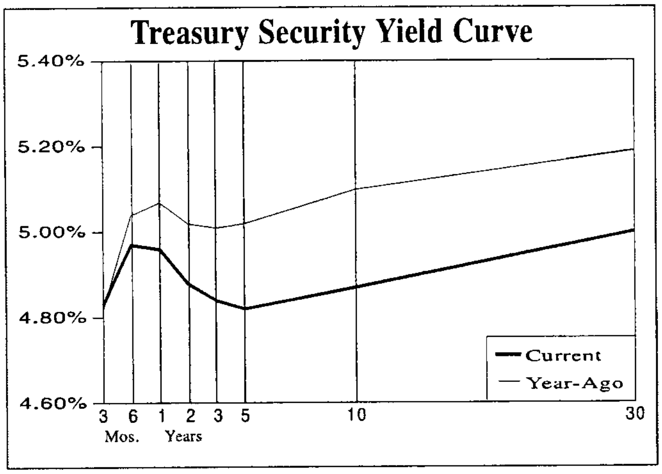
Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.68	vs. Previous Year	115.69%	vs. Previous Year	-8.01%
Trailing 12 Months:	22.43	vs. Previous Quarter	175.00%	vs. Previous Quarter:	-%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.78	03/31/07	7.66	03/31/07	2.20
Price/Cash Flow	5.89	12/31/06	6.87	12/31/06	1.97
Price / Sales	-	09/30/06	7.33	09/30/06	2.16
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	1.29	12/31/06	1.28	12/31/06	-
09/30/06	-	09/30/06	-	09/30/06	3.59
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	10.00	12/31/06	10.00	12/31/06	18.66
09/30/06	-	09/30/06	-	09/30/06	-
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	110.75	12/31/06	0.89	12/31/06	47.01
09/30/06	-	09/30/06	-	09/30/06	-

ATTACHMENT C

Selected Yields

	Recent (5/30/07)	3 Months Ago (2/28/07)	Year Ago (6/01/06)
TAXABLE			
Market Rates			
Discount Rate	6.25	6.25	6.00
Federal Funds	5.25	5.25	5.00
Prime Rate	8.25	8.25	8.00
30-day CP (A1/P1)	5.23	5.23	5.00
3-month LIBOR	5.36	5.35	5.27
Bank CDs			
6-month	3.10	3.28	3.07
1-year	3.72	3.88	3.88
5-year	3.91	3.92	4.04
U.S. Treasury Securities			
3-month	4.83	5.12	4.82
6-month	4.97	5.11	5.04
1-year	4.96	4.93	5.07
5-year	4.82	4.52	5.02
10-year	4.87	4.57	5.10
10-year (inflation-protected)	2.52	2.19	2.43
30-year	5.00	4.68	5.19
30-year Zero	4.97	4.61	5.08



	Recent (5/30/07)	3 Months Ago (2/28/07)	Year Ago (6/01/06)
Mortgage-Backed Securities			
GNMA 6.5%	5.79	5.63	6.03
FHLMC 6.5% (Gold)	5.97	5.73	6.24
FNMA 6.5%	5.92	5.63	6.20
FNMA ARM	5.50	5.60	4.95
Corporate Bonds			
Financial (10-year) A	5.84	5.38	6.04
Industrial (25/30-year) A	5.96	5.62	6.25
Utility (25/30-year) A	6.18	5.65	6.25
Utility (25/30-year) Baa/BBB	6.31	5.89	6.62
Foreign Bonds (10-Year)			
Canada	4.48	4.03	4.40
Germany	4.40	3.96	4.00
Japan	1.74	1.64	1.95
United Kingdom	5.24	4.80	4.64
Preferred Stocks			
Utility A	7.29	7.22	7.23
Financial A	6.39	6.35	6.32
Financial Adjustable A	5.53	5.53	N/A
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.38	4.19	4.57
25-Bond Index (Revs)	4.55	4.48	5.23
General Obligation Bonds (GOs)			
1-year Aaa	3.63	3.56	3.52
1-year A	3.73	3.66	3.63
5-year Aaa	3.74	3.55	3.67
5-year A	3.85	3.64	3.91
10-year Aaa	3.89	3.67	4.07
10-year A	4.39	4.20	4.35
25/30-year Aaa	4.24	3.97	4.53
25/30-year A	4.54	4.28	4.78
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.63	4.39	4.60
Electric AA	4.57	4.38	4.59
Housing AA	4.81	4.44	4.73
Hospital AA	4.80	4.45	4.83
Toll Road Aaa	4.65	4.39	4.80

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/23/07	**5/9/07**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1297	1470	-173	1563	1597	1623
Borrowed Reserves	113	71	42	69	118	205
Net Free/Borrowed Reserves	1184	1399	-215	1494	1480	1418

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/14/07	**5/7/07**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1366.9	1372.6	-5.7	1.4%	0.9%	-1.5%
M2 (M1+savings+small time deposits)	7226.2	7228.1	-1.9	7.2%	7.7%	6.5%

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783
TABLE OF CONTENTS TO SCHEDULES WAR

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
COST OF CAPITAL SUMMARY

WEIGHTED COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) CAPITAL RATIO	(C) RUCO COST	(D) WEIGHTED COST
1	SHORT-TERM DEBT	$ 5,000	3.97%	6.36%	0.25%
2	LONG-TERM DEBT	59,486	47.18%	8.22%	3.88%
3	COMMON EQUITY	61,587	48.85%	9.30%	4.54%
4	TOTAL CAPITALIZATION	$ 126,073	100.00%		
5	**WEIGHTED COST OF CAPITAL**				8.67%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): COLUMN (B) ÷ COLUMN (A), LINE 4
COLUMN (C): LINE 1 - SCHEDULE WAR-1, PAGE 2, LINE 6
LINE 2 - SCHEDULE WAR-1, PAGE 2, LINE 9
LINE 2 - SCHEDULE WAR-1, PAGE 3, LINE 7
COLUMN (D): COLUMN (B) x COLUMN (C)

COST OF LONG AND SHORT-TERM DEBT

LINE NO.	(A) DESCRIPTION	(B) OUTSTANDING BALANCE	(C) ANNUAL INTEREST	(D) INTEREST RATE
1	UNS ELECTRIC SENIOR NOTE	$ 60,000	$ 4,566	7.610%
2	LESS: UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE AND LOSS ON REAQUIRED DEBT	514		
3	ADD: AMORTIZATION OF DEBT DISCOUNT AND EXPENSE AND LOSS ON REAQUIRED DEBT		278	
4	ADD: CREDIT FACILITY COMMITMENT FEES		45	
5	TOTAL LONG-TERM DEBT - NET	$ 59,486	$ 4,889	
6	**COST OF LONG-TERM DEBT - NET**			8.22%
7	UNS SHORT-TERM DEBT	$ 5,000	$ 318	
8	TOTAL SHORT-TERM DEBT	$ 5,000	$ 318	
9	**COST OF SHORT-TERM DEBT**			6.36%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (D): COLUMN (C) ÷ COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	7.89%	SCHEDULE WAR-2, COLUMN (C), LINE 9
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	9.85%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 9
5	CAPM - ARITHMETIC MEAN ESTIMATE	11.56%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 9
6	AVERAGE OF CAPM ESTIMATES	10.70%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE**	9.30%	(LINE 2 + LINE 6) ÷ 2

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	CHG	CH ENERGY GROUP	4.52%	+	2.70%	=	7.22%
2	CNL	CLECO CORPORATION	3.24%	+	3.77%	=	7.01%
3	HE	HAWAIIAN ELECTRIC	4.88%	+	4.22%	=	9.10%
4	MGEE	MGE ENERGY, INC.	3.93%	+	4.30%	=	8.24%
5	NU	NORTHEAST UTILITIES	2.51%	+	4.08%	=	6.60%
6	NST	NSTAR	3.62%	+	6.01%	=	9.62%
7	PSD	PUGET ENERGY, INC.	3.87%	+	3.94%	=	7.81%
8	UIL	UIL HOLDINGS	5.04%	+	2.52%	=	7.56%
9	**AVERAGE**						7.89%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND YIELD CALCULATION

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	CHG	CH ENERGY GROUP	$2.16	÷	$47.83	=	4.52%
2	CNL	CLECO CORPORATION	0.90	÷	27.75	=	3.24%
3	HE	HAWAIIAN ELECTRIC	1.24	÷	25.40	=	4.88%
4	MGEE	MGE ENERGY, INC.	1.39	÷	35.39	=	3.93%
5	NU	NORTHEAST UTILITIES	0.80	÷	31.84	=	2.51%
6	NST	NSTAR	1.30	÷	35.95	=	3.62%
7	PSD	PUGET ENERGY, INC.	1.00	÷	25.83	=	3.87%
8	UIL	UIL HOLDINGS	1.73	÷	34.31	=	5.04%
9	**AVERAGE**						3.95%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 04/16/2007 TO 06/08/2007 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 4
PAGE 1 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	CHG	CH ENERGY GROUP	2.70%	+	0.00%	=	2.70%
2	CNL	CLECO CORPORATION	3.10%	+	0.67%	=	3.77%
3	HE	HAWAIIAN ELECTRIC	3.35%	+	0.87%	=	4.22%
4	MGEE	MGE ENERGY, INC.	4.30%	+	0.00%	=	4.30%
5	NU	NORTHEAST UTILITIES	3.65%	+	0.43%	=	4.08%
6	NST	NSTAR	6.00%	+	0.01%	=	6.01%
7	PSD	PUGET ENERGY, INC.	3.75%	+	0.19%	=	3.94%
8	UIL	UIL HOLDINGS	2.00%	+	0.52%	=	2.52%
11	**AVERAGE**						3.94%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	CHG	CH ENERGY GROUP	0.01%	x	{ [((1.45) + 1) ÷ 2] - 1 }	=	0.00%
2	CNL	CLECO CORPORATION	1.70%	x	{ [((1.78) + 1) ÷ 2] - 1 }	=	0.67%
3	HE	HAWAIIAN ELECTRIC	2.00%	x	{ [((1.87) + 1) ÷ 2] - 1 }	=	0.87%
4	MGEE	MGE ENERGY, INC.	0.01%	x	{ [((1.97) + 1) ÷ 2] - 1 }	=	0.00%
5	NU	NORTHEAST UTILITIES	1.27%	x	{ [((1.68) + 1) ÷ 2] - 1 }	=	0.43%
6	NST	NSTAR	0.01%	x	{ [((2.31) + 1) ÷ 2] - 1 }	=	0.01%
7	PSD	PUGET ENERGY, INC.	1.00%	x	{ [((1.37) + 1) ÷ 2] - 1 }	=	0.19%
8	UIL	UIL HOLDINGS	1.25%	x	{ [((1.84) + 1) ÷ 2] - 1 }	=	0.52%
9	**AVERAGE**						0.34%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	CHG	CH ENERGY GROUP	2002	-0.0189		7.10%		NMF	30.31	16.06	
2			2003	0.2230		9.10%		2.03%	30.80	15.76	
3			2004	0.1970		8.60%		1.69%	31.31	15.76	
4			2005	0.2313		8.80%		2.04%	31.97	15.76	
5			2006	0.1563		7.90%		1.23%	32.54	15.76	
6			GROWTH 2002 - 2006					1.75%	1.50%		-0.47%
7			2007	0.2000		8.00%		1.60%		15.76	0.00%
8			2008	0.2421		8.50%		2.06%		15.00	-2.44%
9			2010-12	0.3046		9.00%		2.74%	2.00%	15.00	-0.98%
10											
11	CNL	CLECO CORPORATION	2002	0.4079		13.10%		5.34%	11.77	47.04	
12			2003	0.2857		12.50%		3.57%	10.09	47.18	
13			2004	0.3182		11.90%		3.79%	10.83	49.62	
14			2005	0.3662		10.70%		3.92%	13.69	49.99	
15			2006	0.3382		8.50%		2.88%	15.05	58.00	
16			GROWTH 2002 - 2006					3.90%	4.00%		5.38%
17			2007	0.2800		8.00%		2.24%		59.00	1.72%
18			2008	0.3077		8.00%		2.46%		60.00	1.71%
19			2010-12	0.3143		10.00%		3.14%	6.50%	63.00	1.67%
20											
21	HE	HAWAIIAN ELECTRIC	2002	0.2346		11.30%		2.65%	14.21	73.62	
22			2003	0.2152		10.80%		2.32%	14.36	75.84	
23			2004	0.0882		8.90%		0.79%	15.01	80.69	
24			2005	0.1507		9.70%		1.46%	15.02	80.98	
25			2006	0.0677		9.90%		0.67%	13.44	81.46	
26			GROWTH 2002 - 2006					1.58%	2.00%		2.56%
27			2007	0.0462		9.50%		0.44%		83.50	2.50%
28			2008	0.1143		10.00%		1.14%		85.50	2.45%
29			2010-12	0.2914		12.00%		3.50%	0.50%	87.00	1.32%
30											
31	MGEE	MGE ENERGY, INC.	2002	0.2071		12.80%		2.65%	12.94	17.57	
32			2003	0.2105		11.60%		2.44%	14.34	18.34	
33			2004	0.2316		10.00%		2.32%	16.59	20.39	
34			2005	0.1274		9.30%		1.18%	16.81	20.45	
35			2006	0.3252		10.50%		3.42%	16.95	20.70	
36			GROWTH 2002 - 2006					2.40%	6.50%		4.18%
37			2007	0.3286		12.00%		3.94%		20.70	0.00%
38			2008	0.3500		12.00%		4.20%		20.70	0.00%
39			2010-12	0.4235		10.50%		4.45%	7.00%	20.70	0.00%

REFERENCES: RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007.
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	NU	NORTHEAST UTILITIES	2002	0.5093		6.30%		3.21%	17.33	127.56	
2			2003	0.5323		6.90%		3.67%	17.73	127.70	
3			2004	0.3077		5.10%		1.57%	17.80	129.03	
4			2005	0.3061		5.10%		1.56%	18.46	131.59	
5			2006	0.1098		4.30%		0.47%	18.14	154.23	
6			GROWTH 2002 - 2006					2.10%	3.00%		4.86%
7			2007	0.4429		7.00%		3.10%		156.20	1.28%
8			2008	0.4645		8.00%		3.72%		158.20	1.28%
9			2010-12	0.4556		8.00%		3.64%	3.50%	164.20	1.26%
10											
11	NST	NSTAR	2002	0.3669		13.80%		5.06%	12.25	106.07	
12			2003	0.3736		13.70%		5.12%	12.84	106.07	
13			2004	0.3580		13.10%		4.69%	13.52	106.55	
14			2005	0.5246		12.80%		6.71%	14.37	106.81	
15			2006	0.2021		13.10%		2.65%	14.82	106.81	
16			GROWTH 2002 - 2006					4.85%	2.50%		0.17%
17			2007	0.3512		13.50%		4.74%		106.81	0.00%
18			2008	0.3644		13.50%		4.92%		106.81	0.00%
19			2010-12	0.4167		15.00%		6.25%	5.50%	106.81	0.00%
20											
21	PSD	PUGET ENERGY, INC.	2002	0.0242		7.20%		0.17%	16.27	93.64	
22			2003	0.1803		7.00%		1.26%	16.71	99.07	
23			2004	0.2424		8.10%		1.96%	16.24	99.87	
24			2005	0.2958		7.20%		2.13%	17.52	115.70	
25			2006	0.3056		7.90%		2.41%	18.15	116.58	
26			GROWTH 2002 - 2006					1.59%	1.50%		5.63%
27			2007	0.3750		8.50%		3.19%		117.00	0.36%
28			2008	0.3939		8.50%		3.35%		117.75	0.50%
29			2010-12	0.4000		9.50%		3.80%	4.00%	124.25	1.28%
30											
31	UIL	UIL HOLDINGS	2002	0.0649		9.10%		0.59%	20.28	23.79	
32			2003	-0.3952		6.00%		NMF	20.65	23.86	
33			2004	-0.1234		6.70%		NMF	22.84	24.01	
34			2005	-0.3308		5.80%		NMF	22.39	24.32	
35			2006	0.0699		9.90%		0.69%	18.53	24.86	
36			GROWTH 2002 - 2006					0.64%	1.00%		1.11%
37			2007	0.0649		9.50%		0.62%		25.20	1.37%
38			2008	0.1128		10.00%		1.13%		25.40	1.08%
39			2010-12	0.1953		10.50%		2.05%	-1.00%	26.60	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
GROWTH RATE COMPARISON

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS			(D) VALUE LINE HISTORIC EPS			(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS		
				EPS	DPS	BVPS	EPS	DPS	BVPS		EPS	DPS	BVPS
1	CHG	2.70%	-	3.00%	1.00%	2.00%	-2.50%	-	1.50%	1.00%	4.83%	0.00%	1.79%
2	CNL	3.77%	12.00%	4.00%	4.00%	6.50%	1.00%	2.00%	4.00%	4.79%	-2.74%	0.00%	6.34%
3	HE	4.22%	4.90%	4.00%	-	0.50%	-1.00%	-	2.00%	2.08%	-4.81%	0.00%	-1.38%
4	MGEE	4.30%	-	6.00%	0.50%	7.00%	2.00%	1.00%	6.50%	3.83%	5.07%	0.92%	6.98%
5	NU	4.08%	13.00%	12.00%	6.50%	3.50%	-	16.50%	3.00%	9.08%	-6.65%	8.33%	1.15%
6	NST	6.01%	6.30%	8.50%	7.00%	5.50%	3.50%	3.00%	2.50%	5.19%	3.38%	9.53%	4.88%
7	PSD	3.94%	4.00%	6.00%	3.00%	4.00%	-4.50%	-11.50%	1.50%	0.36%	3.81%	-4.65%	2.77%
8	UIL	2.52%	-	5.50%	-	-1.00%	-8.50%	-	1.00%	-0.75%	0.13%	0.00%	-2.23%
9				6.13%	3.67%	3.50%	-1.43%	2.20%	2.75%		0.38%	1.77%	2.54%
10	AVERAGES	3.94%	8.04%		4.43%			1.17%		3.20%		1.56%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
CAPM COST OF EQUITY CAPITAL

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	CHG	k	=	4.85%	+ [	0.85	x (	10.40%	-	4.85%	)]	=	9.57%
2	CNL	k	=	4.85%	+ [	1.30	x (	10.40%	-	4.85%	)]	=	12.06%
3	HE	k	=	4.85%	+ [	0.75	x (	10.40%	-	4.85%	)]	=	9.01%
4	MGEE	k	=	4.85%	+ [	0.80	x (	10.40%	-	4.85%	)]	=	9.29%
5	NU	k	=	4.85%	+ [	0.90	x (	10.40%	-	4.85%	)]	=	9.85%
6	NST	k	=	4.85%	+ [	0.80	x (	10.40%	-	4.85%	)]	=	9.29%
7	PSD	k	=	4.85%	+ [	0.85	x (	10.40%	-	4.85%	)]	=	9.57%
8	UIL	k	=	4.85%	+ [	0.95	x (	10.40%	-	4.85%	)]	=	10.12%
9	**AVERAGE**					0.90							9.85%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 05/04/2007 THROUGH 06/08/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	CHG	k	=	4.85%	+ [	0.85	x (	12.30%	-	4.85%	)]	=	11.18%
2	CNL	k	=	4.85%	+ [	1.30	x (	12.30%	-	4.85%	)]	=	14.53%
3	HE	k	=	4.85%	+ [	0.75	x (	12.30%	-	4.85%	)]	=	10.44%
4	MGEE	k	=	4.85%	+ [	0.80	x (	12.30%	-	4.85%	)]	=	10.81%
5	NU	k	=	4.85%	+ [	0.90	x (	12.30%	-	4.85%	)]	=	11.56%
6	NST	k	=	4.85%	+ [	0.80	x (	12.30%	-	4.85%	)]	=	10.81%
7	PSD	k	=	4.85%	+ [	0.85	x (	12.30%	-	4.85%	)]	=	11.18%
8	UIL	k	=	4.85%	+ [	0.95	x (	12.30%	-	4.85%	)]	=	11.93%
9	**AVERAGE**					0.90							11.56%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\,ß\,(r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 05/04/2007 THROUGH 06/08/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

ECONOMIC INDICATORS - 1990 TO PRESENT

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.16%	3.16%	3.17%	4.57%	5.38%	5.78%
17	2006	2.50%	3.30%	7.97%	5.97%	4.97%	4.83%	4.88%	5.94%	6.30%
18	CURRENT	2.60%	0.60%	8.25%	6.25%	5.25%	4.73%	4.88%	6.07%	6.21%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/08/2007
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/08/2007
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 9

LINE NO.		CHG	PCT.	CNL	PCT.	HE	PCT.	MGEE	PCT.		
1	DEBT	$ 337,889.0	38.8%	$ 669,341.0	42.8%	$ 1,309,457.0	53.7%	$ 237,284.0	38.7%		
2											
3	PREFERRED STOCK	21,027.0	2.4%	20,092.0	1.3%	34,293.0	1.4%	0.0	0.0%		
4											
5	COMMON EQUITY	512,862.0	58.8%	876,129.0	56.0%	1,095,240.0	44.9%	375,348.0	61.3%		
6											
7	TOTALS	$ 871,778.0	100%	$ 1,565,562.0	100%	$ 2,438,990.0	100%	$ 612,632.0	100%		
8											
9										ELECTRIC COMPANY SAMPLE	
10		NU	NST	NST	PCT.	PSD	PCT.	UIL	PCT.	AVERAGE	PCT.
11											
12	DEBT	$ 2,965,312.0	50.4%	$ 2,360,775.0	59.2%	$ 2,183,360.0	51.8%	$ 408,603.0	47.0%	$ 1,309,002.6	51.2%
13											
14	PREFERRED STOCK	116,200.0	2.0%	43,000.0	1.1%	1,889.0	0.0%	0.0	0.0%	$ 29,562.6	1.2%
15											
16	COMMON EQUITY	2,798,179.0	47.6%	1,582,563.0	39.7%	2,027,047.0	48.1%	460,581.0	53.0%	$ 1,215,993.6	47.6%
17											
18	TOTALS	$ 5,879,691.0	100%	$ 3,986,338.0	100%	$ 4,212,296.0	100%	$ 869,184.0	100%	$ 2,554,558.9	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding UNS Electric Corporation's ("Company" or "UNS") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for electric service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended June 30, 2006.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of five sets of data requests, the review and analysis of Company responses to Arizona Corporation Commission ("Commission" or "ACC") Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to UNS.

In Decision No. 66028, dated July 03, 2003, the Commission approved a Settlement Agreement, which authorized UNS to acquire the gas and electric assets of Citizens Communications Company ("Citizens"). The Settlement Agreement required present rates and charges for utility service to remain unchanged. The test year used in determining the present rates was the 12-month period ending March 31, 1995.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income, revenue requirements and rate design. RUCO's witness Mr. William Rigsby will provide an analysis of the cost of capital.

RUCO's witness Ms. Marylee Diaz Cortez will also address additional issues related to rate base, operating income, rate design and revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and rate design issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Fair Value Rate Base – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

Accumulated Depreciation – This adjustment reflects RUCO's computation of the test-year level of accumulated depreciation.

Acquisition Adjustment – No Adjustment.

Plant Held For Future Use – No Adjustment.

Construction Work In Progress – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Accumulated Deferred Income Taxes - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Allowance For Working Capital - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Operating Income

Customer Annualization - No adjustment.

Weather Normalization - No adjustment.

Service Fees and Late Fees - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Purchased Power Derivatives - No adjustment.

Demand Side Management and Renewables - No adjustment.

Customer Assistance Residential Energy Support – No adjustment.

Payroll - No adjustment.

Payroll Tax - No adjustment.

Pensions and Benefits – This adjustment to benefit expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

Post-Retirement Medical - No adjustment.

Worker's Compensation – This adjustment converts the amount reflected in the test-year operating expense from a cash basis to an accrual.

Incentive Compensation – This adjustment removes all incentive compensation expenses, because the awards were paid despite non-performance of goals and did not provide additional benefits to ratepayers.

Rate Case Expense – This adjustment is based on RUCO's determination of the fair and reasonable cost to UNS ratepayers for this application process.

Bad Debt Expense – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Interest On Customer Deposits – No adjustment.

Operating Lease Expense - No adjustment.

Fleet Fuel Expense - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Postage Expense – This adjustment reflects the RUCO's annualization of the customer base and a known and measurable postal increase.

Out Of Period Expense - No adjustment.

Year End Accurals - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Franchise Fee Expense - No adjustment.

Membership Dues - No adjustment.

Capitalized Administration and General Expenses - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Depreciation and Property Tax For Construction Work In Progress - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Common Systems Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Operating Systems Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Corporate Cost Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Annualized Depreciation and Amortization Expenses– This adjustment reflects the level of test-year depreciation expense based on RUCO's adjusted gross plant in service and the Company–proposed depreciation rates.

Valencia Turbine Fuel - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Property Tax – This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Supplemental Executive Retirement Plan – This adjustment reflects RUCO's disallowance of the supplemental executive retirement plan.

RUCO Adjustments To Test-Year Operating Expenses – This adjustment to operating expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

RUCO Adjustment To Overhead Line Maintenance Expense – This adjustment normalizes the test-year level of overhead line maintenance expense.

Customer Service Cost Allocations – This adjustment reflects the appropriate level of customer service costs given the quality of the service.

Non-Recurring/Atypical Expenses – This adjustment removes costs not expected to recur and considered atypical for inclusion in test year expenses.

Outside Services – DSM - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Income Tax – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, RUCO is recommending that the increase in the Company's revenue requirement not exceed:

UNS	RUCO	DIFFERENCE
$8,507,097	$1,253,233	($7,253,864)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

UNS	RUCO	DIFFERENCE
5.37 %	0.79 %	-4.58 %

RUCO's recommended decrease in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base

("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

UNS	RUCO	DIFFERENCE
$177,802,340	$161,618,144	($16,184,196)

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-3, RLM-4, RLM-5 and RLM-6.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

UNS	RUCO	DIFFERENCE
$13,946,320	$11,169,957	($2,776,363)

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Determination Of Fair Value Rate Base

Q. Please explain the basis for your determination of the FVRB as shown on Schedule RLM-1.

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustments to the various rate base determinants. Second, the value of the RCND was computed. As shown on supporting Schedule RLM-2, RUCO computed RCND by multiplying RUCO's OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Ms. Diaz Cortez. As shown on Schedule RLM-3, I was responsible for Adjustment No. 2. These adjustments established the initial level and subsequently calculated the present test-year level of gross plant in service and accumulated depreciation. Ms. Diaz Cortez analyzed the remaining rate base adjustments.

<u>RUCO Rate Base Adjustment No. 2 – Adjust Understated Accumulated Depreciation</u>

Q. Please provide the background to RUCO's adjustment.

A. By analyzing the Company's responses to several RUCO data requests (i.e. 1.08, 2.09, 2.10, 4.04 and 5.03), I was able to substantiate the Company's recorded level of gross plant in service as $380,192,497 as of June 30, 2006.

However, UNS states in the instant filing the value of accumulated depreciation of $159,524,693 as of end of the test year. RUCO calculated the appropriate level of accumulated depreciation as $161,819,805, a difference of $2,295,112. RUCO's computation is based on the adjustments in annual gross plant levels and the authorized depreciation rates as provided by the Company.

Therefore, as shown on Schedule RLM-4, column (C), this adjustment decreases the rate base by $2,295,112.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. The Company proposed thirty-one adjustments to its historical test-year operating income. RUCO analyzed the Company's adjustments and made several additional adjustments to the operating income as filed by the Company. The testimony of RUCO witness Ms. Diaz Cortez discusses twenty of the adjustments, while I was responsible for reviewing eleven of the adjustments the Company proposes to its test-year operating income. Finally, as a result of its discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

Operating Income Adjustment No. 2 – Pension and Benefits

Q. Please explain your adjustment to reduce the pension and benefits expenses.

A. My adjustment reflects the information provided by the Company in its response to Staff data request 3.81. UNS quantifies the test-year expenses identified as gifts, awards, employee dinners, picnics and social events. RUCO considers these benefits as an inappropriate financial burden on ratepayers and therefore, removed them from operating expenses.

As shown on Schedule RLM-8, column (C), I reversed the Company's benefit expenses as listed on UNS response to Staff data request 3.81 and decreased test-year operating expenses by $11,612.

Operating Income Adjustment No. 3 – Worker's Compensation

Q. Please discuss the Company's proposed worker's compensation expense adjustment.

A. The Company has converted the amount reflected in the test-year operating expenses from an accrual to a cash basis.

Q. Please explain RUCO's treatment of the Company's proposed worker's compensation expense adjustment.

A. Absent a Commission ruling, RUCO does not consider it appropriate to arbitrarily change from an accrual to a cash basis. The UNS argument that since worker's compensation is a benefit provided to former or inactive employees it should receive the same treatment as post employment benefits is hollow. The Company failed to provide documentation segregating any worker's compensation benefits that are included in post employment benefit obligations.

Furthermore, workers' compensation certainly is provided to active employees for which post-retirement accounting would not be applicable.

The Company accepted the same adjustment as recommended by RUCO in the recently filed UNS Gas rate case.

Therefore, as shown on Schedule RLM-8, column (D), I reversed the Company's cash treatment of worker's compensation expense to an accrual basis and decreased test-year operating expenses by $63,252.

Operating Income Adjustment No. 4 – Incentive Compensation

Q. Please provide the background for this adjustment.

A. In 2004, the Unisource Energy Corporation awarded incentive payments under the Performance Enhancement Plan ("PEP").

The PEP is only eligible for a select group of non-union employees and is paid after meeting certain performance goals, including certain financial goals.

In 2005, Unisource Energy Corporation did not meet the PEP financial goals; and therefore, no payments under the PEP program were awarded. Nevertheless, the Board of Directors authorized a Special Recognition Award to these non-union employees in recognition of their accomplishments; however, this special award was less than the payment awarded in 2004.

The Company's adjusted test-year expense incorporates the average of the 2004 PEP bonus and the 2005 Special Recognition Award.

Q. Please continue and provide an explanation for RUCO's adjustment to the incentive compensation expenses.

A. After reviewing the Company's response to RUCO's data requests 2.13 and Staff data requests 3.83 and 3.113, it became apparent the ratepayers should not be burdened with the Board of Directors' arbitrary decision to authorize a Special Recognition Award to select UNS employees when they did not meet Unisource Energy's 2005 financial performance goal. This "Special" award is unique and does not meet the criteria of a typical and recurring test-year expense; moreover, it rewards employees for non-performance.

RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. Therefore, RUCO dismisses the Company's proposal to average the 2005 Special Recognition Award with the 2004 PEP program.

Further to RUCO's objection to averaging the incentive compensation expenses over two years, the Company states that 60 percent of the PEP bonus is directly related to financial performance and operational cost containment. Stockholders are the beneficiaries of the achievement of these financial components. This is particularly true between rate cases. Any additional profit the Company is able to achieve between rate cases accrues solely to the Company's stockholders. Accordingly, since stockholders stand to gain from the achievement of the financial component, stockholders should bear all of the cost of this portion of the incentive compensation. These costs should not be considered for inclusion in rates.

Moreover, RUCO consistently scrutinizes any incentive compensation thoroughly to ensure ratepayers receive adequate benefit from the expense incurred. While the majority of a customer's interfacing with the Company is done through the rank and file unionized employees who are not eligible for any PEP compensation, the perceived incremental increase in customer service generated by this incentive package would not be cost beneficial to ratepayers.

Therefore, RUCO disallows the Company's special test-year compensation bonus and would consider the PEP program (had it been implemented in the test year) discriminatory because the benefit is provided only to a subset of employees. The bonus is also of limited incremental benefit to the ratepayers because the benefit is offered to a class of employees that does not directly affect the service quality of customers.

As shown on Schedule RLM-8, column (E), my adjustment decreases adjusted test-year expenses by $106,567.

Operating Income Adjustment No. 5 – Rate Case Expense

Q. Please discuss your review of the Company's proposed rate case expenses.

A. The Company has budgeted $600,000 for rate case expenses. RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment. In comparison, RUCO recommended $251,000 as the appropriate level of rate case expense in UNS's recently filed Gas Division rate case; Docket No. G-04204A-06-0463.

Pending the Commission's approval or rejection of RUCO's recommended rate case expense for the UNS Gas Division, RUCO believes the instant case warrants the equivalent level of rate case expense because of the similarities in Company witnesses, testimonies and schedules.

Therefore, this adjustment reduces annual rate case expense from the Company's proposed level of $200,000 ($600,000 / 3 years) to RUCO's recommended level of $83,667 ($251,000 / 3 years).

As shown on Schedule RLM-8, Column (F), this adjustment decreased test-year expenses by $116,333.

Operating Income Adjustment No. 8 – Postage Expense

Q. Please explain your adjustment to reduce the postage expenses.

A. My adjustment consists of two elements. First, I increased the expense to recognize two changes in postal rates, effective January 8, 2006 and May 14, 2007.

Second, I annualized the test-year postage expense to match RUCO's annualized customer count.

As shown on Schedule RLM-8, column (I) and supporting Schedule RLM-9, my adjustment decreases adjusted test-year expenses by $37,956.

Operating Income Adjustment No. 13 – Depreciation Expenses

Q. Please explain your adjustment to reduce depreciation expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustment No. 3 disallowing construction work in progress ("CWIP") from rate base.

RUCO agrees with the set of depreciation rates that UNS is proposing to implement on a going forward basis.

These depreciation rates were revised to reflect the Company's response to Staff Data Request 3.39. I computed test-year depreciation by multiplying RUCO's level of test-year gross plant in service by the Company's proposed depreciation rates.

As shown on Schedule RLM-8, column (N) and supporting Schedule RLM-10, my adjustment decreases adjusted test-year expenses by $142,085.

Operating Income Adjustment No. 15 – Property Tax

Q. Do you agree with UNS's methodology for computing property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

The difference in the amount I have calculated versus the Company is a result of our respective levels of recommended net plant in service. RUCO also used the assessment ratio of 23 percent, which will be valid when the authorized rates in this case become effective (January 2008).

The decreasing assessment ratios as authorized in the Arizona Revised Statues relating to property taxes states the effective rate from December 31, 2008 through December 31, 2009 to be 23 percent.

The assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014.

As shown on Schedule RLM-8, column (P) and supporting Schedule RLM-11, this adjustment decreased test-year expenses by $409,902.

<u>Adjustments To Operating Expenses No. 16 – Supplemental Executive Retirement Plan</u>

Q. Please explain the basis for the adjustment you made to the Pension and Benefits operating expenses.

A. I made an adjustment to the Supplemental Executive Retirement Plan ("SERP") portion of the pension and benefits operating expenses.

Q. Please explain your adjustment to the SERP.

A. As explained in the Company's responses to Staff data request 3.83 and RUCO data request 2.06, UNS's test-year payroll loadings include the cost of a SERP. The Company's test-year operating expenses include $83,506 related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing electric service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In recent ACC Decisions did the Commissioners determine whether SERP expenses were recoverable?

A. Yes. In SWG's latest rate case (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses and it is not reasonable to place this additional burden on ratepayers. Moreover, the Commission voted on June 18, 2007 to disallow SERP in the Arizona Public Service rate case (Decision No. unavailable). Therefore, I have removed the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-8, column (Q), this adjustment decreased test-year expenses by $83,506.

<u>Operating Income Adjustment No. 17 – Disallowance of Inappropriate and/or Unnecessary Expenses</u>

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of electric service.

A After review of all the journal entries in various FERC accounts and the Company's response to a number of RUCO data requests, I determined there were numerous expenditures that were either questionable, inappropriate and/or unnecessary.

Therefore, as shown on Schedule RLM-12 and supporting workpapers attached, I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of Electric service. The back-up documentation denoting each individual expense removed is recorded in Exhibit B (attached to RLM-12): FERC Account Code 921, pages 1 to 4, FERC Account 923, page 1, and FERC Account 930, pages 1 and 2.

A sampling of the 336 questionable expenses submitted by RUCO includes invoices for: 1) $746.96 for a barbeque grill; 2) $608.40 for flags; 3) $8,078.22 for refreshments; 4) $1,377.50 to various Chamber of Commerce, and 5) $1,126.25 for chartered bus tours.

As shown on Schedule RLM-8, column (R) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $73,620.

Adjustments To Operating Expenses No. 18 – Overhead Line Maintenance

Q. Please explain the basis for the adjustment you made to overhead line maintenance expense.

A. Through discovery I reviewed and analyzed four years of expenses recorded in FERC account 593 – overhead line maintenance from 2003 through 2006. My analysis indicated this expense was sufficiently volatile to recommend a test year adjustment to acknowledge the wide variation in annual costs.

Therefore, my adjusted test year expense in the instant case is the calculated four-year average of the "inflation adjusted" annual overhead line maintenance expenses for 2003 through 2006. My adjustment is necessary to normalize the test-year level of overhead maintenance expenses.

As shown on Schedule RLM-8, column (S) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $267,678.

Operating Income Adjustment No. 19 – Customer Service Cost Allocations

Q. Please provide the background for this adjustment.

A. Prior to May 1, 2005, the Call Center duties for UNS Electric were performed in-house by sixteen UNS Electric Customer Service

Representatives at seven office locations for a cost the Company estimates at $321,640 per month for those four months.

After May 1, 2005, Unisource Energy consolidated the call center operations of UNS Gas, UNS Electric and TEP at an actual allocated cost to UNS Electric of $362,013 per month for those eight months, a 12.55 percent increase in cost.

RUCO does not agree that such a dramatic increase in costs is warranted given that the integrated call center and customer service functions continue to provide approximately the same quality of service, as did in-house customer service.

Q. Please continue and provide an explanation for RUCO's adjustment to the allocated customer service costs.

A. RUCO is disallowing this expenditure because evidence provided by the Commission Consumer Services Section indicates the quality of customer service has not improved since the Unisource Energy choose to integrate similar job functions among its affiliates. The Commission Consumer Services Section Report ("Report") on UNS Electric states, in 2004, 15.3 percent of the consumer complaints were based on "quality of service" issues.

As of May 23, 2007, the report states, 2007 year-to-date, 15.3 percent of the consumer complaints are based on "quality of service" issues.

Since the Report does not demonstrate the improvements, enhancements and synergy promoted by the Company as justification for the increased expenditure has translated into increased customer satisfaction, RUCO is removing any increase in this expense until the Company provides documentation that the overall customer satisfaction level has improved.

As shown on Schedule RLM-8, column (T) and supporting Schedule RLM-14, this adjustment decreased test-year expenses by $66,797.

<u>Adjustments To Operating Expenses No. 20 – Non-Recurring/Atypical Expenses</u>

Q. Please explain the basis for the adjustments you made to disallow non-recurring and/or atypical operating expenses.

A. This is similar to an adjustment made in the UNS's recently filed Gas Division rate case, Docket No. G-04204A-06-0463, where the Company agreed that this is not a recurring or typical test-year expense.

Through the discovery process associated with the UNS Gas rate case, Company witness Mr. Smith and I discussed line by line the general ledger details provided by the Company in response to RUCO's data request 4.01 designated as "Procard Details – Data Request RUCO 4.01", pages 1 through 4. During that conversation I expressly asked for clarification of the entries noted as "M.A.R.C. Training (Union Training)". Mr. Smith indicated this training was a one-time only instructional session to acquaint Company personnel with working in a unionized environment. Based on that conversation with Mr. Smith, I selectively excluded only expenses denoted "M.A.R.C. Training (Union Training)" from data provided. This particular adjustment in the instant case culminated in RUCO data request 5.04. In the Company's response to this data request UNS Electric recorded test-year non-recurring expenses of $14,251 for "M.A.R.C. Training".

Therefore as shown on Schedule RLM-8, column (U), this adjustment decreased test-year expenses by $14,251.

<u>Operating Income Adjustment No. 22 – Income Tax Expense</u> – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-8, column (AC) and supporting Schedule RLM-15, this adjustment increased test-year expenses by $1,332,851.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, it is. As shown on Schedule RLM-18, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 122 basis points from 9.89 to 8.67 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION: Athabasca University
Bachelor's Degree in Business Administration - 1993

EXPERIENCE: Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Utility Company	Docket No.
Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al.
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015
UNS Gas, Inc.	G-04204A-06-0463 et al.
Arizona-American Water Company	WS-01303A-06-0403

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TABLE OF CONTENTS TO RUCO SCHEDULES

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 140,991,324	$ 214,613,357	$ 177,802,340	$ 128,777,882	$ 194,458,406	$ 161,618,144
2	Adjusted Operating Income (Loss)	$ 8,742,011	$ 8,742,011	$ 8,742,011	$ 10,404,382	$ 10,404,382	$ 10,404,382
3	Current Rate Of Return (Line 2 / Line 1)	6.20%	4.07%	4.92%	8.08%	5.35%	6.44%
4	Required Operating Income (Line 5 X Line 1)	$ 13,946,320	$ 13,946,320	$ 13,946,320	$ 11,169,957	$ 11,169,957	$ 11,169,957
5	Required Rate Of Return	9.89%	6.50%	7.84%	8.67%	5.74%	6.91%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 5,204,309	$ 5,204,309	$ 5,204,309	$ 765,575		$ 765,575
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6346	1.6346	1.6346	1.6370		1.6370
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 8,507,097	$ 8,507,097	$ 8,507,097	$ 1,253,233		$ 1,253,233
9	Adjusted Test Year Revenue			$ 158,486,890	$ 158,535,538		$ 158,535,538
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 166,993,987	$ 159,788,771		$ 159,788,771
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			5.37%	0.79%		0.79%
12	Rate Of Return On Common Equity			11.39%	9.30%		9.30%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Column (D): Schedules RLM-1, Page 2, RLM-2, RLM-7 And RLM-18
Column (E): Schedule RLM-2
Column (F): Average Of Column (D) + Column (E)

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Company Schedule C-3, Line 2	0.0051
3	Subtotal	Line 1 - Line 2	0.9949
4	Less: Combined Federal And State Tax Rate	Line 14	0.3840
5	Subtotal	Line 3 - Line 4	0.6109
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6370**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate		0.3400
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3163
12	Subtotal	Line 8 + Line 11	0.3860
13	Revenue Less Uncollectibles	Line 3	0.9949
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	0.3840

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 390,513,651	$ 612,326,062	$ 501,419,857	156.80%	$ 379,752,198	$ 595,452,086	$ 487,602,142
2	Accumulated Depreciation	(159,524,693)	(257,585,628)	(208,555,161)	161.47%	(161,819,805)	(261,291,561)	(211,555,683)
3	Net Utility Plant In Service	$ 230,988,958	$ 354,740,434	$ 292,864,696		$ 217,932,393	$ 334,160,525	$ 276,046,459
4	Citizens Acquisition Discount	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)	160.88%	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)
5	Accumulated Amortization	11,224,066	18,123,969	14,674,018	161.47%	11,224,066	18,123,969	14,674,018
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ (131,937,446)	$ (106,993,361)		$ (82,049,275)	$ (131,937,446)	$ (106,993,361)
7	Total Net Utility Plant	$ 148,939,683	$ 222,802,988	$ 185,871,336		$ 135,883,118	$ 202,223,079	$ 169,053,099
	Deductions:							
8	Cust. Advances For Const.	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)	109.97%	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)
9	Customer Deposits	(3,778,419)	(3,778,419)	(3,778,419)	100.00%	(3,778,419)	(3,778,419)	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	1,780,258	1,467,546	154.16%	382,701	589,961	486,331
11	Total Deductions	$ (11,316,030)	$ (11,557,302)	$ (11,436,666)		$ (12,088,162)	$ (12,747,599)	$ (12,417,880)
12	Allowance - Working Capital	$ 3,367,671	$ 3,367,671	$ 3,367,671	100.00%	$ 4,982,926	$ 4,982,926	$ 4,982,926
13	Regulatory Assets	$ -	$ -	$ -		$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -		$ -	$ -	$ -
15	TOTAL TEST YEAR RATE BASE	$ 140,991,324	$ 214,613,357	$ 177,802,341		$ 128,777,882	$ 194,458,406	$ 161,618,144

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule RLM-3, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

ORIGINAL COST RATE BASE STATEMENT

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 390,513,651	$ (10,761,453)	$ 379,752,198
2	Accumulated Depreciation	(159,524,693)	(2,295,112)	(161,819,805)
3	Net Utility Plant In Service	$ 230,988,958	$ (13,056,565)	$ 217,932,393
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)
5	Accumulated Amortization	11,224,066	-	11,224,066
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ -	$ (82,049,275)
7	Total Net Utility Plant	$ 148,939,683	$ (13,056,565)	$ 135,883,118
	Deductions:			
8	Cust. Advances For Const.	$ (8,692,444)	$ -	$ (8,692,444)
9	Customer Deposits	(3,778,419)	-	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	(772,132)	382,701
11	Total Deductions	$ (11,316,030)	$ (772,132)	$ (12,088,162)
12	Allowance - Working Capital	$ 3,367,671	$ 1,615,255	$ 4,982,926
13	Regulatory Assets	$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -
15	TOTAL OCRB	$ 140,991,324	$ (12,213,442)	$ 128,777,882

References:
Column (A): - Company Schedule B-2
Column (B): - RUCO Adjustments As Per RLM-4, Columns (B) Thru (G)
Column (C): - Sum Of Columns (A) And (B)

SUMMARY OF ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) INTENTIONALLY LEFT BLANK	(C) RUCO ADJUSTMENT NO. 2	(D) RUCO ADJUSTMENT NO. 3	(E) RUCO ADJUSTMENT NO. 4	(F) RUCO ADJUSTMENT NO. 5	(G) RUCO ADJUSTMENT NO. 6	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 390,513,651	$ -	$ -	$ (10,761,453)	$ -	$ -	$ -	$ 379,752,198
2	Accumulated Depreciation	(159,524,693)	-	(2,295,112)	-	-	-	-	(161,819,805)
3	Net Utility Plant In Service	$ 230,988,958	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 217,932,393
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ -	$ -	$ -	$ -	$ -	$ (93,273,341)
5	Accumulated Amortization	11,224,066	-	-	-	-	-	-	11,224,066
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ -	$ -	$ -	$ -	$ -	$ -	$ (82,049,275)
7	Total Net Utility Plant	$ 148,939,683	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 135,883,118
	Deductions:								
8	Cust. Advances For Const.	$ (8,692,444)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,692,444)
9	Customer Deposits	(3,778,419)	-	-	-	-	-	-	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	-	-	-	(888,390)	116,258	-	382,701
11	Total Deductions	$ (11,316,030)	$ -	$ -	$ -	$ (888,390)	$ 116,258	$ -	$ (12,088,162)
12	Allowance - Working Capital	$ 3,367,671	$ -	$ -	$ -	$ -	$ -	$ 1,615,255	$ 4,982,926
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL OCRB	$ 140,991,324	$ -	$ (2,295,112)	$ (10,761,453)	$ (888,390)	$ 116,258	$ 1,615,255	$ 128,777,882

References:
Column (A): - Company Schedule B-2
Column (B): - Intentionally Left Blank
Column (C): - Adjustment No. 2 RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-5, Page 6, Line 46)
Column (D): - Adjustment No. 3 RUCO Adjustment To Remove CWIP From Test-Year Rate Base (See Testimony, MDC)
Column (E): - Adjustment No. 4 RUCO Adjustment To Remove ADIT Related To CIAC From Test-Year Rate Base (See Testimony, MDC)
Column (F): - Adjustment No. 5 RUCO Adjustment To Adjusted ADIT Related To A & G Capitalization From Test-Year Rate Base (See Testimony, MDC)
Column (G): - Adjustment No. 6 Allowance For Working Capital (See MDC-2)
Column (H): - Sum Of Columns (A) Through (G)

TEST YEAR PLANT SCHEDULES
YEAR ENDED DECEMBER 31, 2002

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) DEP. RATES AS FILING	(B) PROPOSED DEP. RATES	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	0.00%	4.00%	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	0.00%	6.59%	-	-	4,219,098	-	(267,350)	3,951,748
3		Total Intangible Plant			$ -	$ -	$ 4,231,006	$ -	$ (267,350)	$ 3,963,656
		Other Production								
4	340	Land & Rights	0.00%	0.00%	$ -	$ -	$ 789,651	$ -	$ -	$ 789,651
5	341	Structures & Improvements	1.38%	2.07%	-	-	619,244	(29,957)	(341,982)	277,262
6	342	Fuel Holders, Producers & Acc.	2.42%	2.51%	-	-	631,364	(30,543)	(75,204)	556,160
7	343	Prime Movers	2.34%	2.53%	-	-	8,684,079	(420,103)	(2,028,185)	6,655,895
8	344	Generators	0.67%	2.33%	-	-	2,309,132	(111,707)	(208,430)	2,100,702
9	345	Accessory Electric Equipment	2.20%	2.35%	-	-	1,685,197	(81,523)	(339,420)	1,345,776
10	346	Misc. Power Plant Equipment	1.87%	2.64%	-	-	493,979	(23,897)	(44,154)	449,824
11		Total Other Production			$ -	$ -	$ 15,212,646	$ (697,730)	$ (3,037,375)	$ 12,175,271
		Transmission :								
12	350	Land & Rights	0.00%	0.55%	$ -	$ -	$ 1,249,979	$ -	$ -	$ 1,249,979
13	352	Structures & Improvements	3.77%	3.13%	-	-	346,422	(16,759)	(124,730)	221,692
14	353	Station Equipment	2.92%	3.15%	-	-	16,025,096	(775,234)	(5,012,905)	11,012,191
15	354	Towers & Fixtures	2.87%	5.03%	-	-	290,612	(14,059)	(86,121)	204,491
16	355	Poles & Fixtures	5.77%	4.48%	-	-	9,740,328	(471,200)	(4,512,361)	5,227,967
17	356	Overhead Conductors & Devices	2.71%	2.66%	-	-	9,355,192	(452,569)	(3,424,562)	5,930,630
18	359	Roads & Trails	2.01%	2.02%	-	-	183,860	(8,894)	(62,159)	121,701
19		Total Transmission Plant			$ -	$ -	$ 37,191,489	$ (1,738,715)	$ (13,222,838)	$ 23,968,651
		Distribution:								
20	360	Land & Rights	0.00%	1.17%	$ -	$ -	$ 1,109,275	$ -	$ -	$ 1,109,275
21	361	Structures & Improvements	3.20%	2.96%	-	-	3,398,247	(164,394)	(497,879)	2,900,368
22	362	Station Equipment	4.82%	4.09%	-	-	27,821,016	(1,345,876)	(10,245,496)	17,575,520
23	364	Poles, Towers & Fixtures	4.23%	4.14%	-	-	67,853,801	(3,282,512)	(26,953,218)	40,900,584
24	365	Overhead Conductors & Devices	4.36%	4.13%	-	-	41,912,117	(2,027,551)	(17,231,020)	24,681,097
25	366	Underground Conduit	4.28%	3.79%	-	-	10,705,488	(517,891)	(2,603,610)	8,101,878
26	367	UG Conductors & Devices	5.36%	4.40%	-	-	16,824,452	(813,904)	(6,701,043)	10,123,409
27	368	Line Transformers	4.93%	4.63%	-	-	35,642,570	(1,724,254)	(16,240,337)	19,402,233
28	369	Services	4.23%	3.76%	-	-	10,208,172	(493,833)	(3,062,392)	7,145,781
29	370	Meters	3.25%	3.11%	-	-	7,565,593	(365,995)	(2,086,182)	5,479,411
30	373	Street Lights & Signal Systems	4.55%	4.04%	-	-	2,996,693	(144,969)	(811,037)	2,185,656
31		Total Distribution Plant			$ -	$ -	$ 226,037,423	$ (10,881,179)	$ (86,432,213)	$ 139,605,210
		General:								
32	389	Land & Rights	0.00%	0.00%	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	2.89%	2.65%	-	-	1,832,359	(88,643)	(637,253)	1,195,106
34	391	Office Furniture & Equipment	3.72%	9.11%	-	-	3,463,513	(167,552)	(831,659)	2,631,853
35	392	Transportation Equipment	25.00%	14.43%	-	-	8,416,254	(407,147)	(5,994,712)	2,421,542
36	393	Stores Equipment	2.62%	3.03%	-	-	107,310	(5,191)	(46,575)	60,736
37	394	Tools, Shop And Garage Equip.	3.02%	3.45%	-	-	1,606,644	(77,723)	(259,335)	1,347,309
38	395	Laboratory Equipment	2.41%	2.50%	-	-	935,958	(45,278)	(148,205)	787,753
39	396	Power Operated Equipment	3.33%	6.92%	-	-	644,863	(31,196)	(382,604)	262,260
40	397	Communication Equipment	4.13%	4.35%	-	-	959,853	(46,434)	(193,156)	766,698
41	398	Miscellaneous Equipment	5.45%	5.56%	-	-	129,333	(6,257)	(77,991)	51,342
42		Total General Plant			$ -	$ -	$ 18,153,669	$ (875,421)	$ (8,571,491)	$ 9,582,178
43		Rounding					$ 99			
44		TOTAL PLANT			$ -	$ -	$ 300,826,332	$ (14,193,045)	$ (111,531,267)	$ 189,294,966

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Requests
Columns (F) (G): RUCO Workpapers - Exhibit (A)
Column (H): Column (E) + Column (G)

TEST YEAR PLANT SCHEDULES - CONT'D
PORTION OF YEAR FROM DECEMBER 31, 2002 ENDED AUGUST 11, 2003

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) COMPANY RECLASSIFIED PER RUCO DR 5.03	(D) NET PLANT ADDITIONS	(E) PLANT RETIRM'TS	(F) TOTAL PLANT VALUE	(G) ACCURAL DEPRECIATION	(H) ACCUMULATED DEPRECIATION	(I) NET PLANT VALUE
		Intangible:									
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	1,145,223	1,145,223	-	5,364,321	-	(267,350)	5,096,971
3		Total Intangible Plant	$ -	$ -	$ 1,145,223	$ 1,145,223	$ -	$ 5,376,229	$ -	$ (267,350)	$ 5,108,879
		Other Production									
4	340	Land & Rights	$ -	$ (23,777)	$ -	$ (23,777)	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	-	619,244	(5,221)	(347,203)	272,041
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	-	631,364	(9,335)	(84,539)	546,825
7	343	Prime Movers	-	-	-	-	-	8,684,079	(124,151)	(2,152,336)	6,531,743
8	344	Generators	-	-	-	-	-	2,309,132	(9,452)	(217,882)	2,091,250
9	345	Accessory Electric Equipment	-	-	-	-	-	1,685,197	(22,651)	(362,071)	1,323,126
10	346	Misc. Power Plant Equipment	-	-	-	-	-	493,979	(5,644)	(49,798)	444,181
11		Total Other Production	$ -	$ (23,777)	$ -	$ (23,777)	$ -	$ 15,188,868	$ (176,454)	$ (3,213,829)	$ 11,975,039
		Transmission :									
12	350	Land & Rights	$ 5,904	$ 22,107	$ -	$ 28,011	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	(141,819)	(364)	(142,183)	(12,571)	191,668	(6,197)	(130,927)	60,741
14	353	Station Equipment	-	-	-	-	-	16,025,096	(285,888)	(5,298,793)	10,726,303
15	354	Towers & Fixtures	231,213	-	-	231,213	-	521,825	(7,123)	(93,244)	428,581
16	355	Poles & Fixtures	919,649	-	-	919,649	-	10,659,976	(359,579)	(4,871,940)	5,788,036
17	356	Overhead Conductors & Devices	979,048	-	-	979,048	(91)	10,334,150	(162,998)	(3,587,560)	6,746,590
18	359	Roads & Trails	-	-	-	-	-	183,860	(2,258)	(64,417)	119,443
19		Total Transmission Plant	$ 2,135,815	$ (119,711)	$ (364)	$ 2,015,739	$ (12,662)	$ 39,194,566	$ (824,043)	$ (14,046,881)	$ 25,147,685
		Distribution:									
20	360	Land & Rights	$ 55,667	$ 1,670	$ -	$ 57,336	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	-	-	-	-	-	3,398,247	(66,438)	(564,317)	2,833,930
22	362	Station Equipment	638,721	120,846	1,218	760,785	-	28,581,801	(830,481)	(11,075,977)	17,505,824
23	364	Poles, Towers & Fixtures	2,472,439	(500,777)	65,859	2,037,521	(45,961)	69,845,361	(1,779,318)	(28,732,536)	41,112,825
24	365	Overhead Conductors & Devices	1,419,377	(348,841)	(70,710)	999,826	(30,597)	42,881,347	(1,129,356)	(18,360,376)	24,520,971
25	366	Underground Conduit	373,437	(5,566)	(13,996)	353,875	(151)	11,059,212	(284,563)	(2,888,173)	8,171,039
26	367	UG Conductors & Devices	811,972	(272,614)	14,229	553,587	(12,073)	17,365,966	(559,824)	(7,260,867)	10,105,099
27	368	Line Transformers	1,266,147	(10,703)	(1,507,227)	(251,783)	(95,472)	35,295,314	(1,068,334)	(17,308,671)	17,986,643
28	369	Services	621,062	(48,057)	-	573,004	(169,668)	10,611,508	(269,027)	(3,331,419)	7,280,089
29	370	Meters	235,131	-	4,975	240,106	(13,949)	7,791,750	(152,469)	(2,238,651)	5,553,099
30	373	Street Lights & Signal Systems	89,652	-	-	89,652	(15,667)	3,070,678	(84,332)	(895,369)	2,175,309
31		Total Distribution Plant	$ 7,983,604	$ (1,064,042)	$ (1,505,652)	$ 5,413,910	$ (383,538)	$ 231,067,795	$ (6,224,143)	$ (92,656,356)	$ 138,411,439
		General:									
32	389	Land & Rights	$ -	$ -	$ 0	$ 0	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	20,973	(39,986)	(19,013)	-	1,813,346	(32,186)	(669,439)	1,143,907
34	391	Office Furniture & Equipment	8,606	-	(1,161,087)	(1,152,482)	(814)	2,310,217	(65,612)	(897,271)	1,412,946
35	392	Transportation Equipment	-	-	(899,227)	(899,227)	(91,553)	7,425,475	(1,209,831)	(7,204,543)	220,932
36	393	Stores Equipment	2,910	-	12,651	15,561	-	122,871	(1,842)	(48,417)	74,454
37	394	Tools, Shop And Garage Equip.	36,004	-	696,713	732,718	-	2,339,362	(36,404)	(295,739)	2,043,623
38	395	Laboratory Equipment	-	-	(127,850)	(127,850)	-	808,108	(12,840)	(161,045)	647,063
39	396	Power Operated Equipment	2,807	-	320,587	323,395	-	968,258	(16,409)	(399,013)	569,245
40	397	Communication Equipment	16,501	-	70,101	86,603	-	1,046,456	(25,312)	(218,468)	827,988
41	398	Miscellaneous Equipment	-	-	(14,690)	(14,690)	-	114,643	(4,062)	(82,053)	32,590
42		Total General Plant	$ 66,828	$ 20,973	$ (1,142,788)	$ (1,054,986)	$ (92,367)	$ 17,006,316	$ (1,404,497)	$ (9,975,988)	$ 7,030,328
43		TOTAL PLANT	$ 10,186,247	$ (1,186,558)	$ (1,503,581)	$ 7,496,108	$ (488,566)	$ 307,833,775	$ (8,629,137)	$ (120,160,404)	$ 187,673,371

References:

Columns (A) (B) (C) (D) (E) (F) (H): Company Response To RUCO Data Requests

Column (G): [(Cl. (D) + Cl. (E)) X RLM-5, Pg 1, Cl. (A) X 223/365 Days X 1/2 yr. conv.] + [(RLM-5, Pg 1, Cl. (E) + Cl. (E)) X RLM-5, Pg 1, Cl. (A) X 142/365 Days]

Column (I): Column (F) + Column (H)

TEST YEAR PLANT SCHEDULES - CONT'D
PORTION OF YEAR FROM AUGUST 11 ENDED DECEMBER 31, 2003

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJUSTMENTS	(C) NET PLANT ADDITIONS	(D) PLANT RETIREMENTS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	-	-	5,364,321	-	(267,350)	5,096,971
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 5,376,229	$ -	$ (267,350)	$ 5,108,879
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(3,325)	(350,528)	268,717
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(5,944)	(90,483)	540,881
7	343	Prime Movers	-	-	-	-	8,684,079	(79,056)	(2,231,392)	6,452,687
8	344	Generators	-	-	-	-	2,309,132	(6,019)	(223,901)	2,085,231
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(14,423)	(376,494)	1,308,702
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(3,594)	(53,392)	440,587
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (112,361)	$ (3,326,190)	$ 11,862,679
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(2,811)	(133,738)	57,930
14	353	Station Equipment	-	-	-	-	16,025,096	(182,045)	(5,480,838)	10,544,258
15	354	Towers & Fixtures	-	-	-	-	521,825	(5,826)	(99,070)	422,755
16	355	Poles & Fixtures	-	-	-	-	10,659,976	(239,292)	(5,111,232)	5,548,745
17	356	Overhead Conductors & Devices	-	-	-	-	10,334,150	(108,953)	(3,696,513)	6,637,637
18	359	Roads & Trails	-	-	-	-	183,860	(1,438)	(65,855)	118,005
19		Total Transmission Plant	$ -	$ -	$ -	$ -	$ 39,194,566	$ (540,365)	$ (14,587,246)	$ 24,607,320
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ -	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	-	-	-	-	3,398,247	(42,306)	(606,623)	2,791,624
22	362	Station Equipment	-	-	-	-	28,581,801	(535,960)	(11,611,937)	16,969,864
23	364	Poles, Towers & Fixtures	-	-	-	-	69,845,361	(1,149,406)	(29,881,942)	39,963,419
24	365	Overhead Conductors & Devices	-	-	-	-	42,881,347	(727,362)	(19,087,738)	23,793,609
25	366	Underground Conduit	-	-	-	-	11,059,212	(184,146)	(3,072,319)	7,986,893
26	367	UG Conductors & Devices	-	-	-	-	17,365,966	(362,126)	(7,622,993)	9,742,973
27	368	Line Transformers	-	-	-	-	35,295,314	(676,954)	(17,985,625)	17,309,689
28	369	Services	-	-	-	-	10,611,508	(174,628)	(3,506,047)	7,105,462
29	370	Meters	-	-	-	-	7,791,750	(98,518)	(2,337,169)	5,454,581
30	373	Street Lights & Signal Systems	-	-	-	-	3,070,678	(54,355)	(949,724)	2,120,954
31		Total Distribution Plant	$ -	$ -	$ -	$ -	$ 231,067,795	$ (4,005,760)	$ (96,662,116)	$ 134,405,679
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	-	-	-	1,813,346	(20,388)	(689,827)	1,123,519
34	391	Office Furniture & Equipment	-	-	-	-	2,310,217	(33,434)	(930,705)	1,379,512
35	392	Transportation Equipment	-	-	-	-	7,425,475	(722,204)	(7,926,747)	(501,272)
36	393	Stores Equipment	-	-	-	-	122,871	(1,252)	(49,669)	73,202
37	394	Tools, Shop And Garage Equip.	-	-	-	-	2,339,362	(27,485)	(323,224)	2,016,138
38	395	Laboratory Equipment	-	-	-	-	808,108	(7,577)	(168,622)	639,486
39	396	Power Operated Equipment	-	-	-	-	968,258	(12,544)	(411,557)	556,701
40	397	Communication Equipment	-	-	-	-	1,046,456	(16,814)	(235,282)	811,174
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(2,431)	(84,484)	30,159
42		Total General Plant	$ -	$ -	$ -	$ -	$ 17,006,316	$ (844,129)	(10,820,117)	$ 6,186,199
		Rounding					$ (1)			
43		TOTAL PLANT	$ -	$ -	$ -	$ -	$ 307,833,774	$ (5,502,615)	(125,663,019)	$ 182,170,757

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Requests
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 2, Cl. (F) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 2, Column (H) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2004

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	5,505,174	-	5,505,174	-	10,869,495	-	(267,350)	10,602,145
3		Total Intangible Plant	$ 5,505,174	$ -	$ 5,505,174	$ -	$ 10,881,403	$ -	$ (267,350)	$ 10,614,053
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(8,546)	(359,073)	260,171
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(15,279)	(105,762)	525,602
7	343	Prime Movers	-	-	-	-	8,684,079	(203,207)	(2,434,600)	6,249,480
8	344	Generators	-	-	-	-	2,309,132	(15,471)	(239,372)	2,069,759
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(37,074)	(413,569)	1,271,628
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(9,237)	(62,629)	431,350
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (288,815)	$ (3,615,005)	$ 11,573,864
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(7,226)	(140,964)	50,704
14	353	Station Equipment	1,889,666	(183,168)	1,706,498	-	17,731,594	(492,848)	(5,973,686)	11,757,909
15	354	Towers & Fixtures	-	-	-	-	521,825	(14,976)	(114,047)	407,778
16	355	Poles & Fixtures	-	-	-	-	10,659,976	(615,081)	(5,726,312)	4,933,664
17	356	Overhead Conductors & Devices	-	-	-	-	10,334,150	(280,055)	(3,976,569)	6,357,581
18	359	Roads & Trails	-	-	-	-	183,860	(3,696)	(69,550)	114,310
19		Total Transmission Plant	$ 1,889,666	$ (183,168)	$ 1,706,498	$ -	$ 40,901,064	$ (1,413,882)	$ (16,001,128)	$ 24,899,936
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ -	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	53,763	-	53,763	-	3,452,010	(109,604)	(716,227)	2,735,783
22	362	Station Equipment	459,333	(179,336)	279,997	-	28,861,798	(1,384,391)	(12,996,327)	15,865,471
23	364	Poles, Towers & Fixtures	-	(69,495)	(69,495)	-	69,775,866	(2,952,989)	(32,834,931)	36,940,935
24	365	Overhead Conductors & Devices	9,138,146	-	9,138,146	-	52,019,493	(2,068,838)	(21,156,576)	30,862,917
25	366	Underground Conduit	33,854	-	33,854	-	11,093,066	(474,059)	(3,546,378)	7,546,688
26	367	UG Conductors & Devices	-	-	-	-	17,365,966	(930,816)	(8,553,808)	8,812,158
27	368	Line Transformers	336,011	431,999	768,010	-	36,063,324	(1,758,990)	(19,744,616)	16,318,708
28	369	Services	2,361,696	-	2,361,696	-	12,973,204	(498,817)	(4,004,863)	8,968,341
29	370	Meters	58,299	-	58,299	-	7,850,049	(254,179)	(2,591,348)	5,258,701
30	373	Street Lights & Signal Systems	15,271	-	15,271	-	3,085,949	(140,063)	(1,089,787)	1,996,162
31		Total Distribution Plant	$ 12,456,373	$ 183,168	$ 12,639,541	$ -	$ 243,707,336	$ (10,572,746)	$ (107,234,862)	$ 136,472,474
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	110,131	-	110,131	-	1,923,477	(53,997)	(743,824)	1,179,653
34	391	Office Furniture & Equipment	865,711	-	865,711	-	3,175,928	(102,042)	(1,032,748)	2,143,180
35	392	Transportation Equipment	140,998	-	140,998	-	7,566,473	(1,873,994)	(9,800,740)	(2,234,267)
36	393	Stores Equipment	-	-	-	-	122,871	(3,219)	(52,889)	69,982
37	394	Tools, Shop And Garage Equip.	233,812	-	233,812	-	2,573,174	(74,179)	(397,404)	2,175,770
38	395	Laboratory Equipment	-	-	-	-	808,108	(19,475)	(188,097)	620,011
39	396	Power Operated Equipment	-	-	-	-	968,258	(32,243)	(443,800)	524,458
40	397	Communication Equipment	46,632	-	46,632	-	1,093,088	(44,182)	(279,463)	813,625
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(6,248)	(90,732)	23,911
42		Total General Plant	$ 1,397,284	$ -	$ 1,397,284	$ -	$ 18,403,600	$ (2,209,579)	$ (13,029,696)	$ 5,373,904
43		TOTAL PLANT	$ 21,248,497	$ -	$ 21,248,497	$ -	$ 329,082,272	$ (14,485,022)	$ (140,148,041)	$ 188,934,231

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 3, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 3, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	1,417,769	(1,679,528)	(261,759)	-	10,607,736	-	(267,350)	10,340,386
3		Total Intangible Plant	$ 1,417,769	$ (1,679,528)	$ (261,759)	$ -	$ 10,619,644	$ -	$ (267,350)	$ 10,352,294
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(8,546)	(367,619)	251,626
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(15,279)	(121,041)	510,323
7	343	Prime Movers	-	-	-	-	8,684,079	(203,207)	(2,637,807)	6,046,272
8	344	Generators	-	-	-	-	2,309,132	(15,471)	(254,843)	2,054,288
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(37,074)	(450,643)	1,234,553
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(9,237)	(71,867)	422,112
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (288,815)	$ (3,903,820)	$ 11,285,049
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(7,226)	(148,190)	43,478
14	353	Station Equipment	(73,949)	-	(73,949)	-	17,657,645	(516,683)	(6,490,369)	11,167,277
15	354	Towers & Fixtures	-	-	-	-	521,825	(14,976)	(129,023)	392,802
16	355	Poles & Fixtures	1,625,193	-	1,625,193	-	12,285,169	(661,967)	(6,388,280)	5,896,890
17	356	Overhead Conductors & Devices	911,507	-	911,507	-	11,245,657	(292,406)	(4,268,975)	6,976,682
18	359	Roads & Trails	-	-	-	-	183,860	(3,696)	(73,246)	110,614
19		Total Transmission Plant	$ 2,462,751	$ -	$ 2,462,751	$ -	$ 43,363,815	$ (1,496,955)	$ (17,498,082)	$ 25,865,733
		Distribution:								
20	360	Land & Rights	$ 29,790	$ -	$ 29,790	$ -	$ 1,196,401	$ -	$ -	$ 1,196,401
21	361	Structures & Improvements	(53,763)	-	(53,763)	-	3,398,247	(109,604)	(825,831)	2,572,415
22	362	Station Equipment	(459,332)	-	(459,332)	-	28,402,466	(1,380,069)	(14,376,396)	14,026,070
23	364	Poles, Towers & Fixtures	5,895,620	-	5,895,620	(74,604)	75,596,882	(3,074,634)	(35,834,960)	39,761,922
24	365	Overhead Conductors & Devices	(3,597,875)	-	(3,597,875)	(110,848)	48,310,770	(2,187,200)	(23,232,928)	25,077,842
25	366	Underground Conduit	1,034,159	-	1,034,159	(358)	12,126,867	(496,907)	(4,042,927)	8,083,940
26	367	UG Conductors & Devices	5,683,664	-	5,683,664	(73,238)	22,976,392	(1,081,175)	(9,561,746)	13,414,646
27	368	Line Transformers	10,062,532	-	10,062,532	(467,431)	45,658,425	(2,014,441)	(21,291,626)	24,366,799
28	369	Services	(2,360,169)	-	(2,360,169)	-	10,613,035	(498,849)	(4,503,712)	6,109,323
29	370	Meters	1,518,174	-	1,518,174	-	9,368,223	(279,797)	(2,871,145)	6,497,078
30	373	Street Lights & Signal Systems	683,780	-	683,780	-	3,769,729	(155,967)	(1,245,754)	2,523,975
31		Total Distribution Plant	$ 18,436,580	$ -	$ 18,436,580	$ (726,479)	$ 261,417,437	$ (11,278,642)	$ (117,787,025)	$ 143,630,413
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	522,261	-	522,261	-	2,445,738	(63,135)	(806,959)	1,638,779
34	391	Office Furniture & Equipment	(9,802)	-	(9,802)	-	3,166,126	(117,962)	(1,150,710)	2,015,416
35	392	Transportation Equipment	1,313,645	-	1,313,645	(1,231,497)	7,648,621	(1,901,887)	(10,471,130)	(2,822,509)
36	393	Stores Equipment	-	-	-	-	122,871	(3,219)	(56,108)	66,763
37	394	Tools, Shop And Garage Equip.	(181,419)	-	(181,419)	-	2,391,755	(74,970)	(472,374)	1,919,381
38	395	Laboratory Equipment	-	-	-	-	808,108	(19,475)	(207,573)	600,535
39	396	Power Operated Equipment	-	-	-	-	968,258	(32,243)	(476,043)	492,215
40	397	Communication Equipment	1,298,628	-	1,298,628	-	2,391,716	(71,961)	(351,425)	2,040,291
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(6,248)	(96,980)	17,663
42		Total General Plant	$ 2,943,313	$ -	$ 2,943,313	$ (1,231,497)	$ 20,115,416	$ (2,291,101)	$ (14,089,301)	$ 6,026,116
43		TOTAL PLANT	$ 25,260,413	$ (1,679,528)	$ 23,580,885	$ (1,957,976)	$ 350,705,181	$ (15,355,513)	$ (153,545,578)	$ 197,159,604

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 4, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 4, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

RATE BASE ADJUSTMENT NO. 2 - REMOVE TEST-YEAR ACCUMULATED DEPRECIATION
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED JUNE 30, 2006

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	(85,082)	-	10,522,654	-	(267,350)	10,255,304
3		Total Intangible Plant	$ -	$ -	$ (85,082)	$ -	$ 10,534,562	$ -	$ (267,350)	$ 10,267,212
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	522,252	-	1,141,496	(6,025)	(373,643)	767,853
6	342	Fuel Holders, Producers & Acc.	-	-	532,473	-	1,163,837	(10,772)	(131,813)	1,032,024
7	343	Prime Movers	-	-	6,729,891	-	15,413,970	(139,815)	(2,777,622)	12,636,349
8	344	Generators	-	-	2,541,445	-	4,850,577	(11,894)	(266,737)	4,583,839
9	345	Accessory Electric Equipment	-	-	1,421,243	-	3,106,440	(26,137)	(476,780)	2,629,659
10	346	Misc. Power Plant Equipment	-	-	416,606	-	910,585	(6,512)	(78,379)	832,206
11		Total Other Production	$ -	$ -	$ 12,163,910	$ -	$ 27,352,778	$ (201,155)	$ (4,104,975)	$ 23,247,804
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(3,583)	(151,773)	39,895
14	353	Station Equipment	-	-	91,728	-	17,749,373	(256,347)	(6,746,715)	11,002,658
15	354	Towers & Fixtures	-	-	-	-	521,825	(7,427)	(136,450)	385,375
16	355	Poles & Fixtures	-	-	(14,814)	-	12,270,355	(351,302)	(6,739,582)	5,530,774
17	356	Overhead Conductors & Devices	-	-	(8,084)	-	11,237,573	(151,072)	(4,420,047)	6,817,526
18	359	Roads & Trails	-	-	-	-	183,860	(1,833)	(75,079)	108,782
19		Total Transmission Plant	$ -	$ -	$ 68,830	$ -	$ 43,432,645	$ (771,563)	$ (18,269,646)	$ 25,163,000
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ 41,484	$ -	$ 1,237,885	$ -	$ -	$ 1,237,885
21	361	Structures & Improvements	-	-	681,251	-	4,079,498	(59,330)	(885,161)	3,194,336
22	362	Station Equipment	-	-	4,546,004	-	32,948,470	(733,203)	(15,109,599)	17,838,871
23	364	Poles, Towers & Fixtures	-	-	687,821	-	76,284,703	(1,592,947)	(37,427,907)	38,856,796
24	365	Overhead Conductors & Devices	-	-	1,409,966	-	49,720,736	(1,059,761)	(24,292,689)	25,428,047
25	366	Underground Conduit	-	-	474,196	-	12,601,063	(262,414)	(4,305,341)	8,295,722
26	367	UG Conductors & Devices	-	-	4,282,615	-	27,259,007	(667,622)	(10,229,367)	17,029,640
27	368	Line Transformers	-	-	1,840,762	-	47,499,187	(1,138,731)	(22,430,357)	25,068,830
28	369	Services	-	-	82,528	-	10,695,563	(223,486)	(4,727,199)	5,968,365
29	370	Meters	-	-	428,519	-	9,796,742	(154,435)	(3,025,580)	6,771,162
30	373	Street Lights & Signal Systems	-	-	41,342	-	3,811,071	(85,523)	(1,331,277)	2,479,794
31		Total Distribution Plant	$ -	$ -	$ 14,516,488	$ -	$ 275,933,925	$ (5,977,451)	$ (123,764,476)	$ 152,169,449
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	-	(593,232)	-	1,852,506	(30,800)	(837,759)	1,014,747
34	391	Office Furniture & Equipment	-	-	54,363	-	3,220,489	(58,907)	(1,209,617)	2,010,872
35	392	Transportation Equipment	-	-	2,691,785	-	10,340,406	(1,115,073)	(11,586,203)	(1,245,797)
36	393	Stores Equipment	-	-	-	-	122,871	(1,596)	(57,704)	65,167
37	394	Tools, Shop And Garage Equip.	-	-	51,019	-	2,442,774	(36,201)	(508,575)	1,934,199
38	395	Laboratory Equipment	-	-	499,621	-	1,307,729	(12,643)	(220,216)	1,087,513
39	396	Power Operated Equipment	-	-	241,068	-	1,209,326	(17,979)	(494,022)	715,304
40	397	Communication Equipment	-	-	(128,921)	-	2,262,795	(47,663)	(399,087)	1,863,708
41	398	Miscellaneous Equipment	-	-	7,168	-	121,811	(3,195)	(100,175)	21,636
42		Total General Plant	$ -	$ -	$ 2,822,871	$ -	$ 22,938,287	$ (1,324,058)	$ (15,413,358)	$ 7,524,929
43		Rounding					299			
44		TOTAL PLANT	$ -	$ -	$ 29,487,017	$ -	$ 380,192,497	$ (8,274,227)	$ (161,819,805)	$ 218,372,393
45		Total Plant As Per Company Books					$ 380,192,497		$ (159,524,693)	
46		RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-4, Column (C))					$ -		$ (2,295,112)	

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 4, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 4, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

RATE BASE ADJUSTMENT NO. 3 - REMOVE CWIP FROM TEST-YEAR RATE BASE
TEST YEAR PLANT SCHEDULES - CONT'D
PRO FORMA ADJUSTMENTS TO TEST YEAR ENDED JUNE 30, 2006

			(A)	(B)	(C)	(D)	(E)	(F)	(G)
			ACQUISITION ADJUSTMENT				RUCO ADJUSTED	RUCO ADJUSTED	RUCO ADJUSTED
LINE NO.	ACCT NO.	ACCOUNT NAME	PLANT ADJUSTMENTS	ACC. DEP ADJUSTMENTS	PLANT HELD FOR FUTURE USE	CWIP	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible:							
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	-	-	10,522,654	(267,350)	10,255,304
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 10,534,562	$ (267,350)	$ 10,267,212
		Other Production							
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	1,141,496	(373,643)	767,853
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	1,163,837	(131,813)	1,032,024
7	343	Prime Movers	-	-	-	-	15,413,970	(2,777,622)	12,636,349
8	344	Generators	-	-	-	-	4,850,577	(266,737)	4,583,839
9	345	Accessory Electric Equipment	-	-	-	-	3,106,440	(476,780)	2,629,659
10	346	Misc. Power Plant Equipment	-	-	-	-	910,585	(78,379)	832,206
11		Total Other Production	$ -	$ -	$ -	$ -	$ 27,352,778	$ (4,104,975)	$ 23,247,804
		Transmission :							
12	350	Land & Rights	$ -	$ -	$ (320,000)	$ -	$ 957,990	$ -	$ 957,990
13	352	Structures & Improvements	-	-	-	-	191,668	(151,773)	39,895
14	353	Station Equipment	-	-	-	-	17,749,373	(6,746,715)	11,002,658
15	354	Towers & Fixtures	-	-	-	-	521,825	(136,450)	385,375
16	355	Poles & Fixtures	-	-	-	-	12,270,355	(6,739,582)	5,530,774
17	356	Overhead Conductors & Devices	-	-	-	-	11,237,573	(4,420,047)	6,817,526
18	359	Roads & Trails	-	-	-	-	183,860	(75,079)	108,782
19		Total Transmission Plant	$ -	$ -	$ (320,000)	$ -	$ 43,112,645	$ (18,269,646)	$ 24,843,000
		Distribution:							
20	360	Land & Rights	$ -	$ -	$ (120,000)	$ -	$ 1,117,885	$ -	$ 1,117,885
21	361	Structures & Improvements	-	-	-	-	4,079,498	(885,161)	3,194,336
22	362	Station Equipment	-	-	-	-	32,948,470	(15,109,599)	17,838,871
23	364	Poles, Towers & Fixtures	-	-	-	-	76,284,703	(37,427,907)	38,856,796
24	365	Overhead Conductors & Devices	-	-	-	-	49,720,736	(24,292,689)	25,428,047
25	366	Underground Conduit	-	-	-	-	12,601,063	(4,305,341)	8,295,722
26	367	UG Conductors & Devices	-	-	-	-	27,259,007	(10,229,367)	17,029,640
27	368	Line Transformers	-	-	-	-	47,499,187	(22,430,357)	25,068,830
28	369	Services	-	-	-	-	10,695,563	(4,727,199)	5,968,365
29	370	Meters	-	-	-	-	9,796,742	(3,025,580)	6,771,162
30	373	Street Lights & Signal Systems	-	-	-	-	3,811,071	(1,331,277)	2,479,794
31		Total Distribution Plant	$ -	$ -	$ (120,000)	$ -	$ 275,813,925	$ (123,764,476)	$ 152,049,449
		General:							
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ 57,580
33	390	Structures & Improvements	-	-	-	-	1,852,506	(837,759)	1,014,747
34	391	Office Furniture & Equipment	-	-	-	-	3,220,489	(1,209,617)	2,010,872
35	392	Transportation Equipment	-	-	-	-	10,340,406	(11,586,203)	(1,245,797)
36	393	Stores Equipment	-	-	-	-	122,871	(57,704)	65,167
37	394	Tools, Shop And Garage Equip.	-	-	-	-	2,442,774	(508,575)	1,934,199
38	395	Laboratory Equipment	-	-	-	-	1,307,729	(220,216)	1,087,513
39	396	Power Operated Equipment	-	-	-	-	1,209,326	(494,022)	715,304
40	397	Communication Equipment	-	-	-	-	2,262,795	(399,087)	1,863,708
41	398	Miscellaneous Equipment	-	-	-	-	121,811	(100,175)	21,636
42		Total General Plant	$ -	$ -	$ -	$ -	$ 22,938,287	$ (15,413,358)	$ 7,524,929
43		TOTAL PLANT	$ -	$ -	$ (440,000)	$ -	$ 379,752,198	$ (161,819,805)	$ 217,932,393
44		Total Plant As Per Company As Filed	$ -	$ -	$ (440,000)	$ 10,761,154	$ 390,513,651	$ (159,524,693)	$ -
45		Difference	$ -	$ -	$ -	$ (10,761,154)	$ (10,761,453)	$ (2,295,112)	$ 217,932,393
48		RUCO Adjustment To Remove CWIP From Rate Base (See RLM-4, Column (D))					$ (10,761,453)		

ferences: Columns (A) (B) (C): RUCO Made No Adjustments To The Company's Filing
Column (D): RUCO Adjustment To Remove CWIP From Rate Base
Column (E): Schedule RLM-5, Page 6, Column (E) + Columns (A) (B) (C) + (D)
Column (F): Schedule RLM-5, Page 6, Column (G)
Column (G): Column (E) + Column (F)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

OPERATING INCOME STATEMENT

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
	Operating Revenues:					
1	Electric Retail Revenues	$ 156,651,860	$ -	$ 156,651,860	$ 1,253,233	$ 157,905,093
2	Sales for Resale	246,016	-	246,016	-	246,016
3	Other Operating Revenue	1,589,014	48,648	1,637,662	-	1,637,662
4	TOTAL OPERATING REVENUES	$ 158,486,890	$ 48,648	$ 158,535,538	$ 1,253,233	$ 159,788,771
	Operating Expenses:					
5	Purchased Power	$ 106,224,185	$ (152)	$ 106,224,033	$ -	$ 106,224,033
6	Total O & M Expense	26,423,248	(1,718,408)	24,704,841	-	24,704,841
7	Depreciation and Amortization	11,812,574	(594,056)	11,218,518	-	11,218,518
8	Taxes Other than Income Taxes	3,447,533	(660,314)	2,787,219	-	2,787,219
9	Income Taxes	1,837,339	1,359,207	3,196,546	487,658	3,684,204
10	TOTAL OPERATING EXPENSES	$ 149,744,879	$ (1,613,723)	$ 148,131,156	$ 487,658	$ 148,618,815
11	OPERATING INCOME (LOSS)	$ 8,742,011	$ 1,662,371	$ 10,404,382	$ 765,575	$ 11,169,957

References:

Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1
Column (E): Column (C) + Column (D)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ. NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ. NO. 3 WORKER'S COMP. TESTIMONY-RLM	(E) ADJ. NO. 4 INCENTIVE COMP. TESTIMONY-RLM	(F) ADJ. NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO. 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ. NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ. NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ. NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ 156,651,860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ 246,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ 1,099,279	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	339,735	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	150,000	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ 1,589,014	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ 158,486,890	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	106,021,950	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	202,235	-	-	-	-	-	-	(152)	-	-
12		**Total Purchased Power**	$ 106,224,185	$ -	$ -	$ -	$ -	$ -	$ -	$ (152)	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ 2,264	$ -	$ -	$ -	$ -	$ -	$ -	$ (454)	$ -	$ -
14	547	Fuel	266,198	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	26,297	-	-	-	-	-	-	(72)	-	-
16	549	Miscellaneous Other Power Generation	52,481	-	-	-	-	-	-	(11)	-	-
17	551	Maintenance Supervision & Engineering	54,625	-	-	-	-	-	-	(561)	-	-
18	553	Maintenance of Generating and Electric Plant	255,461	-	-	-	-	-	-	(1,046)	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	80,460	-	-	-	-	-	-	(555)	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	66,776	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	9,394	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	75,228	-	-	-	-	-	-	(192)	-	-
24	563	Overhead Line Expenses	3,324	-	-	-	-	-	-	(28)	-	-
25	565	Transmission of Electricity by Others	7,009,878	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	19,495	-	-	-	-	-	-	(124)	-	-
27	567	Rents	11,857	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	24	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	20,513	-	-	-	-	-	-	(454)	-	-
31	571	Maintenance of Overhead Lines	7,354	-	-	-	-	-	-	(24)	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	364,166	-	-	-	-	-	-	(500)	-	-
34	581	Load Dispatching	437,055	-	-	-	(799)	-	-	(3,216)	-	-
35	582	Station Expenses	72,715	-	-	-	-	-	-	(244)	-	-
36	583	Overhead Line Expenses	811,053	-	-	-	-	-	-	(1,971)	-	-
37	584	Underground Line Expenses	511,510	-	-	-	-	-	-	(3,868)	-	-
38	585	Street Lighting & Signal System Expenses	1,628	-	-	-	-	-	-	(10)	-	-
39	586	Meter Expenses	743,347	-	-	-	-	-	-	(5,837)	-	-
40	587	Customer Installations Expense	15,998	-	-	-	-	-	-	(102)	-	-
41	588	Miscellaneous Distribution Expenses	351,137	-	(108)	-	(9,375)	-	-	(2,577)	-	-
42	589	Rents	99,440	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	54,430	-	-	-	-	-	-	(560)	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	472,734	-	-	-	-	-	-	(3,198)	-	-
46	593	Maintenance of Overhead Lines	1,006,308	-	-	-	(9,879)	-	-	(5,569)	-	-
47	594	Maintenance of Underground Lines	142,605	-	-	-	-	-	-	(1,062)	-	-
48	595	Maintenance of Line Transformers	103,988	-	-	-	-	-	-	(484)	-	-
49	596	Maintenance of Street Lighting & Signal Systems	56,424	-	-	-	-	-	-	(481)	-	-
50	597	Maintenance of Meters	123	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	7,233	-	-	-	-	-	-	(10)	-	-

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ. NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ. NO. 3 WORKER'S COMP. TESTIMONY-RLM	(E) ADJ. NO. 4 INCENTIVE COMP. TESTIMONY-RLM	(F) ADJ. NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO. 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ. NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ. NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ. NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
		Customer Account Expense										
52	901	Supervision	172,327	-	(25)	-	(14,699)	-	-	(1,453)	-	-
53	902	Meter Reading Expenses	730,556	-	-	-	-	-	-	(774)	-	-
54	903	Customer Records & Collection Expenses	3,834,499	-	(209)	-	(1,600)	-	-	(7,905)	(37,956)	-
55	904	Uncollectible Accounts	579,539	-	-	-	-	-	(203,038)	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	29,171	-	-	-	-	-	-	(117)	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	34,001	-	-	-	-	-	-	(460)	-	-
59	909	Informational and Instructional Advertising Expenses	62,059	-	-	-	(5,850)	-	-	(439)	-	-
60	910	Miscellaneous Customer Service & Informational Expenses	9,779	-	-	-	-	-	-	(11)	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	770,799	-	-	-	(56,045)	-	-	-	-	-
62	921	Office Supplies & Expenses	535,854	-	(10,129)	-	-	-	-	(6,625)	-	-
63	922	Administrative Expenses Transferred - Credit	(158,087)	-	-	-	-	-	-	-	-	-
64	923	Outside Services Employed	3,317,593	-	-	-	-	-	-	-	-	-
65	924	Property Insurance	65,598	-	-	-	-	-	-	-	-	-
66	925	Injuries and Damages	512,417	-	-	(63,252)	-	-	-	(10)	-	-
67	926	Employee Pension & Benefits	1,172,133	-	-	-	-	-	-	-	-	(6,256)
68	928	Regulatory Commission Expenses	200,000	-	-	-	-	(116,333)	-	-	-	-
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	82,478	-	(1,139)	-	-	-	-	-	-	-
71	930.2	Miscellaneous General Expenses	1,148,557	-	-	-	-	-	-	(2,071)	-	-
72	931	Rents	74,558	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	35,937	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ 26,423,248	$ -	$ (11,612)	$ (63,252)	$ (98,247)	$ (116,333)	$ (203,038)	$ (53,098)	$ (37,956)	$ (6,256)
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ 998,011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/406	Other Production Plant	182,444	-	-	-	-	-	-	-	-	-
77	403/404/406	Transmission Plant	1,203,457	-	-	-	-	-	-	-	-	-
78	403/404/406	Distribution Plant	9,059,006	-	-	-	-	-	-	-	-	-
79	403/404/406	General Plant	369,656	-	-	-	-	-	-	-	-	-
80		**Total Depreciation & Amortization - All**	$ 11,812,574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ 192,787	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	327,975	-	-	-	-	-	-	-	-	-
83	408	Property Tax - Distribution	2,284,584	-	-	-	-	-	-	-	-	-
84	408	Property Tax - General	291,025	-	-	-	-	-	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	348,088	-	-	-	(8,320)	-	-	-	-	-
86	408	Medical and Dental	2,773	-	-	-	-	-	-	-	-	-
87	408	Other	301	-	-	-	-	-	-	-	-	-
88		**Total Taxes Other Than Income Taxes**	$ 3,447,533	$ -	$ -	$ -	$ (8,320)	$ -	$ -	$ -	$ -	$ -
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ 1,342,818	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	10,602,572	-	-	-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	(10,108,051)	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ 1,837,339	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	**Total Operating Expense**		$ 149,744,879	$ -	$ (11,612)	$ (63,252)	$ (106,567)	$ (116,333)	$ (203,038)	$ (53,250)	$ (37,956)	$ (6,256)
94	**OPERATING INCOME**		$ 8,742,011									

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

Schedule RLM-8
Pages 3 & 4 of 6

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP. COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZ'N SCH. RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SCH. RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	-
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	547	Fuel	-	-	-	-	(266,198)	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	-
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	-
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	-
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	-
27	567	Rents	-	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	-
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	-
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	-
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	-
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	-
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	-
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	-
42	589	Rents	(54)	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	(267,678)	-
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	-
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	-
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	-
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	-

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

Schedule RLM-8
Pages 3 & 4 of 6

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP. COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZ'N SCH. RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SCH. RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	-
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	-
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	(45,230)
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	-
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	-
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-	-	-	-	(2,346)
62	921	Office Supplies & Expenses	(128)	-	-	-	-	-	-	(21,320)	-	(1,029)
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(12)
64	923	Outside Services Employed	(301,005)	-	-	-	-	-	-	(20,311)	-	(236)
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	(123)
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	(27)
67	926	Employee Pension & Benefits	-	-	-	-	-	-	(83,506)	-	-	(13,242)
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	-
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	-	-	-	-	-	-	-	(3,539)	-	-
71	930.2	Miscellaneous General Expenses	-	-	(10,010)	-	-	-	-	(28,451)	-	-
72	931	Rents	-	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ (301,187)	$ -	$ (10,010)	$ -	$ (266,198)	$ -	$ (83,506)	$ (73,620)	$ (267,678)	$ (62,245)
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ -	$ (11,823)	$ -	$ (7,922)	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/406	Other Production Plant	-	(8,839)	-	(9,640)	-	-	-	-	-	-
77	403/404/406	Transmission Plant	-	(48,805)	-	5,995	-	-	-	-	-	-
78	403/404/406	Distribution Plant	-	(363,618)	-	40,227	-	-	-	-	-	-
79	403/404/406	General Plant	-	(16,731)	-	(170,844)	-	-	-	-	-	(2,156)
80		**Total Depreciation & Amortization - All**	$ -	$ (449,816)	$ -	$ (142,085)	$ -	$ -	$ -	$ -	$ -	$ (2,156)
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ (8,134)	$ -	$ -	$ -	$ (26,392)	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	-	(31,707)	-	-	-	(43,718)	-	-	-	-
83	408	Property Tax - Distribution	-	(181,846)	-	-	-	(301,058)	-	-	-	-
84	408	Property Tax - General	-	(18,009)	-	-	-	(38,733)	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	-
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	-
87	408	Other	-	-	-	-	-	-	-	-	-	(2,397)
88		**Total Taxes Other Than Income Taxes**	$ -	$ (239,696)	$ -	$ -	$ -	$ (409,902)	$ -	$ -	$ -	$ (2,397)
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	**Total Operating Expense**		$ (301,187)	$ (689,512)	$ (10,010)	$ (142,085)	$ (266,198)	$ (409,902)	$ (83,506)	$ (73,620)	$ (267,678)	$ (66,797)
94	**OPERATING INCOME**											

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(U) ADJ. NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) INTENTIONALLY LEFT BLANK	(X) INTENTIONALLY LEFT BLANK	(Y) INTENTIONALLY LEFT BLANK	(Z) INTENTIONALLY LEFT BLANK	(AA) INTENTIONALLY LEFT BLANK	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 22 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,651,860
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 246,016
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,147,927
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	339,735
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	150,000
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,637,662
7		**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,535,538
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	106,021,950
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	202,083
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,224,033
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,810
14	547	Fuel	-	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	26,215
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	52,470
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	54,064
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	254,415
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	79,905
		Transmission Expense										-
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	66,776
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	9,394
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	75,036
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	3,296
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	7,009,878
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	19,371
27	567	Rents	-	-	-	-	-	-	-	-	-	11,657
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	24
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	20,059
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	7,330
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	363,686
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	433,038
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	72,471
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	609,082
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	507,642
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	1,618
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	737,510
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	15,896
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	339,077
42	589	Rents	-	-	-	-	-	-	-	-	-	99,396
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	53,870
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	469,536
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	723,181
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	141,523
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	103,484
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	55,943
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	123
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	7,223

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(U) ADJ. NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) INTENTIONALLY LEFT BLANK	(X) INTENTIONALLY LEFT BLANK	(Y) INTENTIONALLY LEFT BLANK	(Z) INTENTIONALLY LEFT BLANK	(AA) INTENTIONALLY LEFT BLANK	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 22 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	156,148
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	729,782
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	3,741,599
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	376,500
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	29,054
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	(49,920)	-	-	-	-	-	-	-	(16,379)
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	55,770
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	9,767
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-	-	-	-	712,377
62	921	Office Supplies & Expenses	(1,382)	-	-	-	-	-	-	-	-	495,240
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(158,099)
64	923	Outside Services Employed	(12,869)	-	-	-	-	-	-	-	-	2,993,173
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	65,475
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	449,128
67	926	Employee Pension & Benefits	-	-	-	-	-	-	-	-	-	1,069,129
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	83,667
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930 1	General Advertising Expenses	-	-	-	-	-	-	-	-	-	77,800
71	930 2	Miscellaneous General Expenses	-	-	-	-	-	-	-	-	-	1,108,025
72	931	Rents	-	-	-	-	-	-	-	-	-	74,558
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	35,937
74		**Total Operation and Maintenance Expense**	$ (14,251)	$ (49,920)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,704,841
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 978,366
76	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	-	163,965
77	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	-	1,160,647
78	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	-	8,735,615
79	403/404/406	General Plant	-	-	-	-	-	-	-	-	-	179,925
80		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,218,518
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,261
82	408	Property Tax - Transmission	-	-	-	-	-	-	-	-	-	252,550
83	408	Property Tax - Distribution	-	-	-	-	-	-	-	-	-	1,801,680
84	408	Property Tax - General	-	-	-	-	-	-	-	-	-	234,283
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	339,768
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	2,773
87	408	Other	-	-	-	-	-	-	-	-	-	(2,096)
88		**Total Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,787,219
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 2,702,025
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	10,602,572
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	(10,108,051)
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 3,196,546
93	**Total Operating Expense**		$ (14,251)	$ (49,920)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 148,131,156
94	**OPERATING INCOME**											$ 10,404,382

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

OPERATING INCOME ADJUSTMENT NO. 8
NORMALIZATION OF POSTAGE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE		(A) POSTAGE
	Calculation To Annualize Postage Costs To Recognize January 2006 Postal Increase			
1	Actual Test-Year Postal Costs	Company Workpapers	$	275,038
2	Actual Postal Costs January Thru June (Including Postal Increase)	Company Workpapers		146,957
3	RUCO Estimate Of Postage Costs Prior January Postal Increase	Line 1 - Line 2	$	128,081
4	January 8, 2006 Postage Increase			5.00%
5	Annualized Postage Cost For January Postal Increase	Line 3 + 5.00% Increase	$	134,485
6	RUCO Total Annualized Test-Year Postage Cost	Line 2 + Line 5	$	281,442
	Calculation To Normalize Postage Costs To Recognize May 2007 Postal Increase			
7	May 14, 2007 Postage Increase			5.13%
8	RUCO Adjusted Postage Cost To Recognize January 2006 Increase	Line 6 + 5.13% Increase		295,875
	Calculation To Annualize Postage Costs To Recognize Annualized Customer Base			
9	RUCO Adjusted Postage Cost To Recognize January 2006 Increase	Line 8	$	295,875
10	Actual Number Of Test-Year Customer Bills	Company Schedule H-2		89,596
11	Cost Per Customer Bill	Line 9 / Line 10	$	3.3023
12	RUCO Annualized Number Of Test-Year Customer Bills	Company Workpapers		91,864
13	RUCO Adjusted Postage Costs For Annualized Customer Base	Line 11 X Line 12	$	303,365
14	Company As Filed	Company Workpapers		341,321
15	Difference	Line 13 - Line 14	$	(37,956)
16	RUCO Adjustment (See RLM-8, Pages 1 & 2, Column (I))	Line 15	$	(37,956)

OPERATING INCOME ADJUSTMENT NO. 13
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.	DESCRIPTION	(A) RUCO TOTAL PLANT AS ADJUSTED	(B) COMPANY PROP'D DEP. RATE	(C) RUCO DEPREC'N EXPENSE	(D) CO. COMPUTED NET OF CWIP DEP. EXP.	(E) DIFFERENCE
		Intangible:					
1	302	Franchises & Consents	$ 11,908	4.00%	$ 476		
2	303	Miscellaneous Intangible	10,522,654	6.59%	693,592		
3		Total Intangible Plant	$ 10,534,562		$ 694,069	$ 701,891	$ (7,822)
		Other Production					
	340	Land & Rights	$ 765,874	0.00%	$ -		
7	341	Structures & Improvements	1,141,496	2.07%	23,629		
8	342	Fuel Holders, Producers & Acc.	1,163,837	2.51%	29,212		
9	343	Prime Movers	15,413,970	2.53%	389,973		
10	344	Generators	4,850,577	2.33%	113,018		
11	345	Accessory Electric Equipment	3,106,440	2.35%	73,001		
12	346	Misc. Power Plant Equipment	910,585	2.64%	24,039		
13		Total Other Production	$ 27,352,778		$ 652,874	$ 662,514	$ (9,640)
14		Transmission :					
	350	Land & Rights	$ 957,990	0.55%	$ 5,239		
15	352	Structures & Improvements	191,668	3.13%	5,999		
	353	Station Equipment	17,749,373	3.15%	559,105		
16	354	Towers & Fixtures	521,825	5.03%	26,248		
17	355	Poles & Fixtures	12,270,355	4.48%	549,712		
18	356	Overhead Conductors & Devices	11,237,573	2.66%	298,919		
19	359	Roads & Trails	183,860	2.02%	3,714		
20		Total Transmission Plant	$ 43,112,645		$ 1,448,937	$ 1,442,942	$ 5,995
21		Distribution:			-		
22	360	Land & Rights	$ 1,117,885	0.15%	$ 1,654		
23	361	Structures & Improvements	4,079,498	2.96%	120,753		
24	362	Station Equipment	32,948,470	4.09%	1,347,592		
25	364	Poles, Towers & Fixtures	76,284,703	4.14%	3,158,187		
26	365	Overhead Conductors & Devices	49,720,736	4.13%	2,053,466		
27	366	Underground Conduit	12,601,063	3.79%	477,580		
28	367	UG Conductors & Devices	27,259,007	4.40%	1,199,396		
29	368	Line Transformers	47,499,187	4.63%	2,199,212		
30	369	Services	10,695,563	3.76%	402,553		
	370	Meters	9,796,742	3.11%	304,679		
31	373	Street Lights & Signal Systems	3,811,071	4.04%	153,967		
		Total Distribution Plant	$275,813,925		$ 11,419,040	$ 11,378,813	$ 40,227
32		General:					
33	389	Land & Rights	$ 57,580	0.00%	$ -		
34	390	Structures & Improvements	1,852,506	2.65%	49,091		
35	391	Office Furniture & Equipment	3,220,489	9.11%	293,529		
36	392	Transportation Equipment	10,340,406	13.20%	1,365,407		
37	393	Stores Equipment	122,871	3.03%	3,723		
38	394	Tools, Shop And Garage Equip.	2,442,774	3.45%	84,276		
39	395	Laboratory Equipment	1,307,729	2.50%	32,693		
40	396	Power Operated Equipment	1,209,326	6.92%	83,685		
41	397	Communication Equipment	2,262,795	4.35%	98,432		
42	398	Miscellaneous Equipment	121,811	5.56%	6,773		
43		Total General Plant	$ 22,938,287		$ 2,017,609	$ 2,188,453	$ (170,844)
		SUB TOTALS			$ 16,232,528	$ 16,374,613	$ (142,085)
44		Annualized Amortization - Acquisition Discount			(3,781,656)	(3,781,656)	
45		Vehicle Depreciation Charged To CWIP			(897,691)	(897,691)	
46		Adjustment Difference - Booked Value To Company Computation			117,308	117,308	
47		TOTALS	$379,752,198		$ 11,670,489	$ 11,812,574	$ (142,085)
48		Company Test-Year Depreciation As Filed			$ 11,812,574		
49		Difference			$ (142,085)		
50		RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (N))			$ (142,085)		

UNS Electric, Inc.
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OPERATING INCOME ADJUSTMENT NO. 15
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service (RLM-4, Column (H), Line 7)		$ 135,883,118
2	Licensed Transportation (Company Workpapers)	$ (3,834,788)	
3	Land Cost And Rights (Company Workpapers)	(1,816,844)	
4	Environmental Property (Company Workpapers)	(5,563,286)	
5	Non-Taxable WAPA Portion Of N Havasu Sub	(4,674,822)	
6	CWIP In Rate Base	(10,802,316)	
7	Net Book Value Of Generation	(17,285,854)	
8	Full Cash Value Of Generation	7,943,440	
9	Land FCV Per ADOR (Company Workpapers)	1,551,539	
10	Material And Supplies (Company Workpapers)	5,650,559	
11	COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 10)		$ 107,050,746
	Calculation Of The Company's Tax Liability:		
8	Assessment Ratio (Per House Bill 2779)	23.0%	
9	Assessed Value (Line 7 X Line 8)	$ 24,621,672	
10	Average Tax Rate (Company Workpapers)	9.69%	
13	PROPERTY TAX Excluding Environmental Property (Line 9 X Line 10)		$ 2,384,806
14	Environmental Property (Line 4)	$ 5,563,286	
15	Statutory FCV Adjustment (Company Workpapers)	50%	
16	Environmental Property FVC (Line14 X Line 15)	$ 2,781,643	
17	Asessment Ratio Line 8)	23.0%	
18	Taxable Value (Line 16 X Line 17)	$ 639,778	
19	Average Tax Rate (Company Workpapers)	9.69%	
20	PROPERTY TAX On Environmental Property (Line 18 X Line 19)		$ 61,968
21	PROPERTY TAX On Leased Property (Company Workpapers)		
22	COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 13, 20 & 21)		$ 2,446,773
23	Total Test Year Adjusted Property Tax Expense Per Company's Filing	$ 3,096,371	
24	Property Tax Associated With CWIP	(239,696)	
25	Rounding	(8)	
26	Net Test Year Adjusted Property Tax Expense Per Company's Filing	$ 2,856,667	
27	Decrease In Property Tax Expense (Line 22 - Line 26)	$ (409,893)	

LINE NO.	Distribution Of Property Tax Adjustment	COMPANY WORKPAPERS	ALLOCATION FACTOR	RUCO ALLOCATION
28	Generation	$ 184,653	6.44%	$ (26,392)
29	Transmission	305,868	10.67%	(43,718)
30	Distribution	2,106,338	73.45%	(301,058)
31	General/Intangible	270,993	9.45%	(38,733)
32	Totals	$ 2,867,852	100.00%	$ (409,902)

LINE NO.	DESCRIPTION	(B)
33	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 24) (See RLM-8, Pages 3 & 4, Column (P))	$ (409,902)

UNS Electric, Inc.
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OPERATING INCOME ADJUSTMENT NO. 17
RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT
	Expenses Removed		
1	Account 921 - A & G Expense - Office Supplies:	RUCO Workpapers - Exhibit B 0921	(21,320)
2	Account 923 - A & G Expense - Outside Services Employed:	RUCO Workpapers - Exhibit B 0923	(20,311)
3	Account 930 - A & G Expense - Miscellaneous General Expenses:	RUCO Workpapers - Exhibit B 0930	(28,451)
4	Total Expenses Removed	Sum Of Lines 1 Thru 6	$ (70,081)
5	RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (R) For Distribution)	Line 7	$ (70,081)

UNS Electric Corporation
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Test Year Ended June 30, 2006

EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
AUG-05	0921	Projects	PVS Net - Procard Charges		906 FASTRIP FOOD S	47.33		47.33	Inappropriate - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		A FRAME OF MIND	38.83		38.83	Inappropriate - Employee Plaque
AUG-05	0921	Projects	PVS Net - Procard Charges		AIRTRANAI 33212712643762	228.39		228.39	Out-Of-State Expense ?
JUL-05	0921	Projects	PVS Net - Procard Charges		ALADDIN-ZANZIBAR CAFE	29.75		29.75	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		ALBERTSONS #967 S9H	23.45		23.45	Inappropriate - Emplloyee Meeting
MAR-06	0921	Projects	PVS Net - Procard Charges		AZ REPUBLIC SUBSCRIPTI	200.20		200.20	Newspaper Subscription
FEB-06	0921	Projects	PVS Net - Procard Charges		AZ TOWN HALL	50.00		50.00	**Sponsorship - UNSE Agrees To Remove**
OCT-05	0921	Projects	PVS Net - Procard Charges		BARLEY BROTHERS BREWER	40.13		40.13	Inappropriate - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		BARNES & NOBLE #2962	27.02		27.02	Office Supplies ?
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHA S 30 SYW	10.28		10.28	Inappropriate - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW	5.97		5.97	Inappropriate - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW	22.67		22.67	Inappropriate - Emplloyee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		BEER BOTTOM'S BISTRO	42.75		42.75	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		BRUEGGERS BAGEL BAKERY	7.62		7.62	Inappropriate - Business Meal
FEB-06	0921	Projects	PVS Net - Procard Charges		BRUEGGER'S BAGELS -Q51	2.79		2.79	Inappropriate - Training Meeting
FEB-06	0921	Projects	PVS Net - Procard Charges		CARLTON CARDS #0408	47.97		47.97	Office Supplies ?
SEP-05	0921	Projects	PVS Net - Procard Charges		CHA-BONES	70.40		70.40	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	100.92		100.92	Excessive - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	60.11		60.11	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	50.25		50.25	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	70.83		70.83	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI41600004168	50.33		50.33	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CHINA BUFFET - LH	56.86		56.86	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		CHUYS MESQUITE BROILER	75.34		75.34	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 01773	5.00		5.00	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05540	11.93		11.93	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05923	2.98		2.98	Inappropriate - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		COFFEE BEAN & TEA LEAF	5.37		5.37	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		COLORADO BELLE F/B	10.76		10.76	Out-Of-State Expense?
DEC-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416	51.73		51.73	Excessive - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416	111.39		111.39	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	153.59		153.59	Inappropriate - Employee Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	50.00		50.00	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	121.69		121.69	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	108.79		108.79	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	56.97		56.97	Excessive - Business Meal
AUG-05	0921	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLC	1,855.62		927.81	2-Year Amortization
OCT-05	0921	Projects	PVS Net - Procard Charges		DANONE WATERS OF NORTH	89.50		89.50	Inappropriate - Drinking Water
OCT-05	0921	Projects	PVS Net - Procard Charges		DIAMOND 1624 SHAMROCK	5.55		5.55	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	114.69		114.69	Inappropriate - Employee Meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	30.15		30.15	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	15.97		15.97	Inappropriate - Safety Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		ENOTECA PIZZARIA WINE	63.91		63.91	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	37.00		37.00	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	37.00		37.00	Out-Of-State Expense?
JUN-06	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	45.00		45.00	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	27.00		27.00	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	29.00		29.00	Out-Of-State Expense?
SEP-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	33.00		33.00	Out-Of-State Expense?
JAN-06	0921	Projects	PVS Net - Procard Charges		FOOD CITY #108 STP	14.97		14.97	Inappropriate - Training Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	60.00		60.00	Inappropriate - Flowers
JAN-06	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	98.28		98.28	Inappropriate - Flowers
SEP-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	60.00		60.00	Inappropriate - Flowers
NOV-05	0921	Projects	PVS Net - Procard Charges		GAYLORD TEXAN F&B	16.02		16.02	Out-Of-State Expense?
MAY-06	0921	Projects	PVS Net - Procard Charges		GOLDEN CORRAL 2465	53.19		53.19	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		GOLD'S GYM	40.00		40.00	**Inappropriate - UNSE Agrees To Remove**
OCT-05	0921	Projects	PVS Net - Procard Charges		GREAT LAK 84612472893255	101.50		101.50	Questionable Expense?

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0921	Projects	PVS Net - Procard Charges		GREAT LAK 84615481193795	127.99		127.99	Questionable Expense?
FEB-06	0921	Projects	PVS Net - Procard Charges		H.L.A FRONT DESK #1	85.89		85.89	Questionable Expense?
AUG-05	0921	Projects	PVS Net - Procard Charges		HILTON SEDONA RESORTIP	437.42		437.42	Questionable Expense ?
JUN-06	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241	3.01		3.01	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241	1.93		1.93	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #008	10.75		10.75	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #033	1.92		1.92	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416	137.76		137.76	Inappropriate - Employee Appreciation
OCT-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416	200.00		200.00	Inappropriate - Employee Appreciation
OCT-05	0921	Payables		Purchase Invoices USD	HUALAPAI TRIBE	250.00		250.00	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0921	Projects	PVS Net - Procard Charges		IVARS 25 SEATAC AIRPOR	19.51		19.51	Out-Of-State Expense?
MAR-06	0921	Projects	PVS Net - Procard Charges		JA STEAKHOUSE	80.60		80.60	Excessive - Business Meal
JAN-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	112.80		112.80	Inappropriate - Team Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	51.13		51.13	Excessive - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	210.60		210.60	Excessive - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		JAVELINA CANTINA	55.83		55.83	Excessive - Business Meal
JAN-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM	357.50		357.50	Dues
MAR-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM	30.00		30.00	Dues
DEC-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	222.22		222.22	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	71.72		71.72	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	55.73		55.73	Excessive - Business Meal
FEB-06	0921	Payables		Purchase Invoices USD	KINGMAN MOHAVE LIONS CLUB	60.00		60.00	Dues
AUG-05	0921	Payables		Purchase Invoices USD	KINGMAN ROTARY CLUB	125.00		125.00	Dues
JAN-06	0921	Payables		Purchase Invoices USD	KINGMAN ROTARY CLUB	133.00		133.00	Dues
FEB-06	0921	Payables		Purchase Invoices USD	KINGMAN ROUTE 66 ROTARY CLUB	250.00		250.00	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN-CHILI'00010462	75.63		75.63	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		KMART 00095281	10.76		10.76	Office Supplies ?
MAY-06	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU CHAMBER OF	15.00		15.00	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU-CH00010496	41.79		41.79	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		LK HAVASU CITY CHMBR	35.00		35.00	Dues
NOV-05	0921	Projects	PVS Net - Procard Charges		LOVE AND WAR IN TEXAS	49.52		49.52	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		MACARONI GR30100003012	94.49		94.49	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		MAD DOGS BAR & GRILL	27.28		27.28	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	12.00		12.00	Out-Of-State Expense?
DEC-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	84.00		84.00	Out-Of-State Expense?
FEB-06	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	12.00		12.00	Out-Of-State Expense?
JUN-06	0921	Payables		Purchase Invoices USD	MINKUS ADVERTISING SPECIALTIES	2,357.86		2,357.86	**Inappropriate - UNSE Agrees To Remove**
FEB-06	0921	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C	35.00		35.00	Dues
JUL-05	0921	Projects	PVS Net - Procard Charges		MR. C'S RESTAURANT	193.49		193.49	Inappropriate - HR Related
MAR-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO	27.23		27.23	Inappropriate - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO	52.28		52.28	Inappropriate - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE	173.54		173.54	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE	23.86		23.86	Out-Of-State Expense?
AUG-05	0921	Payables		Purchase Invoices USD	NOGALES INTERNATIONAL NEWSPAPER	49.00		49.00	Newspaper Subscription
SEP-05	0921	Projects	PVS Net - Procard Charges		NORZAGARAY FOOD MARKET	166.79		166.79	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		OMNI HOTELS TUCSON RES	350.16		350.16	Excessive Choice Of Hotel
JUN-06	0921	Projects	PVS Net - Procard Charges		ORB*M57ZGF	901.20		901.20	**Inappropriate - UNSE Agrees To Remove**
SEP-05	0921	Projects	PVS Net - Procard Charges		OUTBACK #0315	76.73		76.73	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		P.F. CHANG'S #8000	104.09		104.09	Inappropriate - Employee Meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		PALO DURO CREEK GOLF C	7.68		7.68	Out-Of-State Expense?
NOV-05	0921	Payables		Purchase Invoices USD	PERFECTION ENTERTAINMENT	350.00		350.00	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS	452.01		452.01	Questionable Expense ?
NOV-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS	894.50		894.50	Questionable Expense?
AUG-05	0921	Projects	PVS Net - Procard Charges		PRESCOTT CONVENTION CT	95.96		95.96	Questionable Expense - UES Mentoring?
JUL-05	0921	Projects	PVS Net - Procard Charges		QUIK MART #33	30.67		30.67	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		QUINN FLAG	608.40		608.40	Inappropriate
NOV-05	0921	Projects	PVS Net - Procard Charges		RAINBOW CRAIG MINI MAR	28.93		28.93	Inappropriate - Business Meal

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
JAN-06	0921	Projects	PVS Net - Procard Charges		RAMADA EXPRESS CSN CGE	150.00		150.00	Inappropriate - Employee Appreciation
APR-06	0921	Projects	PVS Net - Procard Charges		RED ROBIN	74.65		74.65	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		RUBY TUESDAY #4574	124.61		124.61	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00002SC9	25.61		25.61	Inappropriate - Employee Meeting
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	21.30		21.30	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	147.10		147.10	Inappropriate - Employee Appreciation BBQ
DEC-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	117.99		117.99	Inappropriate - Employee Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	24.46		24.46	Inappropriate - Employee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	27.24		27.24	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018SC9	57.63		57.63	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	52.32		52.32	Inappropriate - Employee Appreciation BBQ
OCT-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	27.38		27.38	Inappropriate - Employee Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	56.12		56.12	Inappropriate - Employee Meeting
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289	25.27		25.27	Inappropriate - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020SC9	11.88		11.88	Inappropriate - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		SANDY'S	219.95		219.95	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089	682.09		682.09	Questionable Expense - Office Fridge
NOV-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089	498.74		498.74	Questionable Expense - Office Fridge
AUG-05	0921	Projects	PVS Net - Procard Charges		SHERYL'S HALLMARK #2	7.54		7.54	Inappropriate - Sympathy Card
JUN-06	0921	Projects	PVS Net - Procard Charges		SHORT STOP MINI MARKET	4.75		4.75	Inappropriate - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT	50.00		50.00	Inappropriate - Employee Recognition
JUN-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT	137.95		137.95	Inappropriate - HR Related
AUG-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	126.52		126.52	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	164.34		164.34	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	78.30		78.30	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6	42.84		42.84	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6	20.93		20.93	Inappropriate - Employee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS	6.51		6.51	Inappropriate - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00069Q48	4.04		4.04	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00088Q48	5.51		5.51	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SUBWAY 16276	70.86		70.86	Inappropriate - Employee Appreciation BBQ
NOV-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN HOTEL FD	4.95		4.95	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN SUNST CAFE	16.93		16.93	Out-Of-State Expense?
SEP-05	0921	Projects	PVS Net - Procard Charges		TEQUILA CHARLIE'S	131.59		131.59	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		TERRIBLES #148	14.37		14.37	Inappropriate - Employee Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		TEXAS ROADHOUSE #2204	121.91		121.91	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #0416	746.96		746.96	Inappropriate - Office BBQ
SEP-05	0921	Projects	PVS Net - Procard Charges		THE OLIVE GARD00010959	50.32		50.32	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE	50.96		50.96	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		TONTO APCHE CSNO MZTZL	14.15		14.15	Questionable Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		UNITED WAY OF GREATER	100.00		100.00	**Sponsorship - UNSE Agrees To Remove**
SEP-05	0921	Projects	PVS Net - Procard Charges		USA CHARTER BUS	891.25		891.25	Inappropriate
AUG-05	0921	Projects	PVS Net - Procard Charges		WALGREEN 00035Q39	17.27		17.27	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00052Q39	37.63		37.63	Office Supplies ?
FEB-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39	4.08		4.08	Office Supplies ?
MAY-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39	10.73		10.73	Office Supplies ?
DEC-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	22.55		22.55	Office Supplies ?
FEB-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	13.97		13.97	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	36.03		36.03	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	97.28		97.28	Office Supplies ?
JUN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1364	17.18		17.18	Office Supplies ?
AUG-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	196.19		196.19	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	538.88		538.88	Office Supplies ?
MAR-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	13.46		13.46	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	67.87		67.87	Office Supplies ?
SEP-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	34.65		34.65	Office Supplies ?
AUG-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	127.58		127.58	Office Supplies ?

UNS Electric Corporation
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	80.46		80.46	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	54.67		54.67	Office Supplies ?
JUL-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	10.50		10.50	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	200.92		200.92	Office Supplies ?
APR-06	0921	Projects	PVS Net - Procard Charges		ZIVAZ	51.43		51.43	Excessive - Business Meal
								21,320.24	

UNS Electric Corporation
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0923

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	Invoice Number	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0923	Projects	PVS Net - Procard Charges		AMZ*SUPERSTORE		54.83		54.83	Office Supplies?
JUN-06	0923	Projects	PVS Net - Procard Charges		BELLA DONNA RESTAURANT		62.07		62.07	Excessive - Business Meal
NOV-05	0923	Projects	PVS Net - Procard Charges		CINNABON		8.25		8.25	Inappropriate - Employee Training
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLCA11906		1,953.13		976.57	2-Year Amortization
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLCA22206		1,990.63		995.32	2-Year Amortization
APR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4749208-50	1,106.46		1,106.46	Inappropriate - Drinking Water
AUG-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3378780-50	415.80		415.80	Inappropriate - Drinking Water
JAN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4623406-50	337.87		337.87	Inappropriate - Drinking Water
JUL-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3064550-50	964.73		964.73	Inappropriate - Drinking Water
JUN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	106877	789.57		789.57	Inappropriate - Drinking Water
MAR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4742326-50	27.04		27.04	Inappropriate - Drinking Water
MAY-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4756016-50	574.94		574.94	Inappropriate - Drinking Water
NOV-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4283463-50	608.92		608.92	Inappropriate - Drinking Water
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4053444-50	829.62		829.62	Inappropriate - Drinking Water
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3701642-50	1,309.22		1,309.22	Inappropriate - Drinking Water
NOV-05	0923	Projects	PVS Net - Procard Charges		EDGEWATER HOTEL F/B		58.82		58.82	Out-Of-State Expense?
APR-06	0923	Projects	PVS Net - Procard Charges		FTD*SUTCLIFFE FLORAL		21.62		21.62	Office Supplies?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO ADV DEP		126.44		126.44	Out-Of-State Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		19.34		19.34	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		22.28		22.28	Out-Of-State Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		83.93		83.93	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		245.57		245.57	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO RETAIL		2.00		2.00	Out-Of-State Expense?
DEC-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		22.03		22.03	Inappropriate - Business Meal
FEB-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		18.70		18.70	Inappropriate - Business Meal
MAY-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		17.77		17.77	Inappropriate - Business Meal
NOV-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		20.65		20.65	Inappropriate - Business Meal
JUN-06	0923	Projects	PVS Net - Procard Charges		LOWNS COSTUMES AND NOV		37.50		37.50	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0923	Projects	PVS Net - Procard Charges		LUXOR PYRAMID CAFE		22.00		22.00	Out-Of-State Expense?
SEP-05	0923	Projects	PVS Net - Procard Charges		MAIN STREET CATERING		178.98		178.98	Inappropriate - Employee Meeting
APR-06	0923	Projects	PVS Net - Procard Charges		MARRIOTT HOTELS WEST L		151.52		151.52	Out-Of-State Expense?
APR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		28.93		28.93	Inappropriate - Safety Plaque
MAR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		62.08		62.08	Inappropriate - Safety Plaque
DEC-05	0923	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C		70.00		70.00	**Sponsorship - UNSE Agrees To Remove**
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046547	3,824.30		764.86	Removing 20 % For Lobbying Activities
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046571	3,824.30		764.86	Removing 20 % For Lobbying Activities
JAN-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046839	3,824.30		764.86	Removing 20 % For Lobbying Activities
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0021660-IN	5,004.89		1,000.98	Removing 20 % For Lobbying Activities
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0021788-IN	5,004.89		1,000.98	Removing 20 % For Lobbying Activities
MAR-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0047740	7,648.60		1,529.72	Removing 20 % For Lobbying Activities
NOV-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00045422	3,824.30		764.86	Removing 20 % For Lobbying Activities
OCT-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00044934	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0022010-IN	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0022150-IN	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Projects	PVS Net - Procard Charges		OPEN ROAD TOURES INC		125.00		125.00	Inappropriate
APR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		106.11		106.11	Excessive - Business Meal
MAR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		15.31		15.31	Inappropriate - Business Meal
SEP-05	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		26.63		26.63	Inappropriate - Business Meal
JUL-05	0923	Projects	PVS Net - Procard Charges		PASTO		103.52		103.52	Excessive - Business Meal
SEP-05	0923	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289		11.54		11.54	Inappropriate - Kitchen Supplies
NOV-05	0923	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6		62.16		62.16	Inappropriate - Employee Meeting
OCT-05	0923	Projects	PVS Net - Procard Charges		WESTIN KIERLAND RESTIP		136.18		136.18	Questionable Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		WINDROCK AVIATION		332.00		332.00	Questionable Expense?
SEP-05	0923	Projects	PVS Net - Procard Charges		YAVAPAI BUS TOURS		235.00		235.00	Questionable Expense?
									20,310.51	

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0930

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	tui	Vendor Name	Invoice Number	DR	CR	Net Amount		RUCO'S COMMENT
APR-06	0930	Projects	PVS Net - Procard Charges			ALBERTSONS #1027 S9H		12.27		12.27	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Payables		Purchase Invoices USD		ARIZONA INDEPENDENT SCHEDULING ADMINISTF	2006-25	250.00		250.00	R	Does Not Benefit Ratepayers - Retail Competition
JUL-05	0930	Payables		Purchase Invoices USD		ARIZONA UTILITY INVESTORS ASSOC	072705 500000	2,500.00		2,500.00	R	**Does Not Benefit Ratepayers - UNSE Agrees To Remove**
JUL-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		94.78		94.78	R	Inappropriate - Employee Recognition
OCT-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		50.00		50.00	R	Inappropriate - Employee Recognition
JAN-06	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		98.11		98.11	R	Inappropriate - Employee Recognition
AUG-05	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		10.17		10.17	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		7.20		7.20	R	Inappropriate - Safety Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		13.76		13.76	R	Inappropriate - Safety Meeting
OCT-05	0930	Projects	PVS Net - Procard Charges			BASHAS 60 SYW		4.54		4.54	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BLACK BEAR DINER N		287.78		287.78	R	Inappropriate - Employee Recognition
NOV-05	0930	Payables		Purchase Invoices USD		BOYS & GIRLS CLUB OF NOGALES	110805 3500	35.00		35.00	R	**Sponsorship - UNSE Agrees To Remove**
JUL-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	15944	3,712.50		1,856.25	R	2-Year Amortization
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16252	974.00		487.00	R	2-Year Amortization
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16347	4,677.75		2,338.88	R	2-Year Amortization
MAY-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	17808	3,712.50		1,856.25	R	2-Year Amortization
JUN-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	18010	711.00		355.50	R	2-Year Amortization
JAN-06	0930	Projects	PVS Net - Procard Charges			CHA-BONES		191.25		191.25	R	Inappropriate - 15 Employees Lunch
FEB-06	0930	Projects	PVS Net - Procard Charges			CHILI'S GRI04900010496		79.53		79.53	R	Excessive - Business Meal
JUN-06	0930	Payables		Purchase Invoices USD		CITY OF BULLHEAD CITY	062506 5417	54.17		54.17	R	Dues
JUN-06	0930	Projects	PVS Net - Procard Charges			DIAMOND BACKS MERCHNDI		47.57		47.57	R	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		107.68		107.68	R	Inappropriate - Safety Meeting
NOV-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		116.89		116.89	R	Inappropriate - Safety Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		48.39		48.39	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		103.36		103.36	R	Inappropriate - Safety Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		101.74		101.74	R	Inappropriate - Safety Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		77.52		77.52	R	Inappropriate - Safety Meeting
JUL-05	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000025467C	24,071.00		4,814.20	R	Removing 20 % For Lobbying Activities
JAN-06	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000038367	2,801.90		560.38	R	Removing 20 % For Lobbying Activities
NOV-05	0930	Projects	PVS Net - Procard Charges			ELEPHANT BAR # 219		173.56		173.56	R	Excessive - Business Meal
JUL-05	0930	Projects	PVS Net - Procard Charges			EXPRESS STOP		11.65		11.65	R	Inappropriate - Business Related
NOV-05	0930	Projects	PVS Net - Procard Charges			FIREBIRDS OF CHANDLER		168.20		168.20	R	Excessive - Business Meal
APR-06	0930	Projects	PVS Net - Procard Charges			FLAMINGO ALTA VILLA		59.64		59.64	R	Out-Of-State Expense?
FEB-06	0930	Projects	PVS Net - Procard Charges			FRESH PRODUCE ASSOC		250.00		250.00	R	Dues
SEP-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	JULY 2005	35.00		35.00	R	Dues
OCT-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	07/2005	35.00		35.00	R	Dues
OCT-05	0930	Projects	PVS Net - Procard Charges			H.L.A FRONT DESK #1		229.61		229.61	R	Travel Expense?
APR-06	0930	Projects	PVS Net - Procard Charges			HMS HOST-LAS-AIRPT#241		7.29		7.29	R	Out-Of-State Expense?
OCT-05	0930	Projects	PVS Net - Procard Charges			HOOTERS OF OVERLAND PA		58.87		58.87	R	Out-Of-State Expense?
APR-06	0930	Projects	PVS Net - Procard Charges			HOTEL CONTESSA-HOTEL		1,330.98		1,330.98	R	Out-Of-State Expense?
JAN-06	0930	Projects	PVS Net - Procard Charges			IHOP #3033		80.59		80.59	R	Inappropriate - 7 Employees Lunch
MAR-06	0930	Projects	PVS Net - Procard Charges			JAVELINA CANTINA		56.96		56.96	R	Inappropriate - 4 Employees Lunch
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN CHAMBER OF COMMERCE	207916A	325.00		325.00	R	Dues
MAY-06	0930	Projects	PVS Net - Procard Charges			KINGMAN DELI, THE		81.42		81.42	R	Excessive
OCT-05	0930	Payables		Purchase Invoices USD		KINGMAN MOHAVE LIONS CLUB	1376	60.00		60.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROTARY CLUB	102605 12500	125.00		125.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	100105 13250	132.50		132.50	R	Dues
JUN-06	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	060506 12500	125.00		125.00	R	Dues
AUG-05	0930	Payables		Purchase Invoices USD		KINGSMEN	081505 12500	125.00		125.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KIWANIS CLUB OF LAKE HAVASU	110305 66600	666.00		666.00	R	Dues
DEC-05	0930	Projects	PVS Net - Procard Charges			KMART 00037077		30.44		30.44	R	Supplies?
MAY-06	0930	Projects	PVS Net - Procard Charges			LAKE HAVASU CHAMBER OF		505.00		505.00	R	Dues
APR-06	0930	Projects	PVS Net - Procard Charges			LOS PRIMOS BAR & GRILL		96.21		96.21	R	Inappropriate - 7 Employees OT Meal
DEC-05	0930	Projects	PVS Net - Procard Charges			MARIE CALLENDER'S #245		567.80		567.80	R	Excessive - March Of Dimes
AUG-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		62.00		62.00	R	Out-Of-State Expense?
OCT-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		41.00		41.00	R	Out-Of-State Expense?
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052917	536.50		536.50	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052918	1,118.00		1,118.00	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Payables		Purchase Invoices USD		MOHAVE MUSEUM OF HISTORY & ARTS	080305 20000	200.00		200.00	R	**Inappropriate - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			N AWLINS ON MONTEZUMA		340.71		340.71	R	**Inappropriate - UNSE Agrees To Remove**
JUN-06	0930	Projects	PVS Net - Procard Charges			NATURAL TEASE SPORTWEA		99.87		99.87	R	**Inappropriate - UNSE Agrees To Remove**
JUN-06	0930	Payables		Purchase Invoices USD		NOGALES-SANTA CRUZ CHAMBER OF COMMERCI	060906 6000	60.00		60.00	R	Dues
JUL-05	0930	Projects	PVS Net - Procard Charges			NORTHWEST PUBLIC POW		210.00		210.00	R	Dues
NOV-05	0930	Projects	PVS Net - Procard Charges			OUTBACK #0317		142.86		142.86	R	Excessive - 2 Employees Meals
OCT-05	0930	Projects	PVS Net - Procard Charges			PIZZA HUT 21200Q34		168.89		168.89	R	Inappropriate - 6 Employees Meals
FEB-06	0930	Projects	PVS Net - Procard Charges			PIZZA HUT #00942700Q34		119.66		119.66	R	Inappropriate - Refreshments
FEB-06	0930	Projects	PVS Net - Procard Charges			PLUSHLAND INC		174.00		174.00	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Projects	PVS Net - Procard Charges			PRESCOTT CONVENTION CT		171.74		171.74	R	Questionable Expense - UES Mentoring?
JUN-06	0930	Projects	PVS Net - Procard Charges			PRONTO MARKET		27.01		27.01	R	Inappropriate - Refreshments
MAR-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		50.00		50.00	R	Inappropriate - Employee Appreciatiopn
JUN-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		200.53		200.53	R	**Inappropriate - UNSE Agrees To Remove**
APR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00002162		32.21		32.21	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00012294		250.42		250.42	R	**Inappropriate - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		23.76		23.76	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		31.01		31.01	R	Inappropriate - Refreshments For Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		30.79		30.79	R	Inappropriate - Refreshments For Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		85.76		85.76	R	Inappropriate - Refreshments For Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		28.76		28.76	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SANDY'S		513.24		513.24	R	Questionable Expense - Employee Lunches
FEB-06	0930	Projects	PVS Net - Procard Charges			SANDY'S		65.35		65.35	R	Questionable Expense - Employee Lunches

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0930

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	tui	Vendor Name	Invoice Number	DR	CR	Net Amount		RUCO'S COMMENT
APR-06	0930	Projects	PVS Net - Procard Charges			SANDY'S		133.73		133.73	R	Questionable Expense - Employee Lunches
JUL-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		52.88		52.88	R	Inappropriate - Refreshments For Meeting
AUG-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		60.73		60.73	R	Inappropriate - Refreshments For Meeting
SEP-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		45.88		45.88	R	Inappropriate - Refreshments For Meeting
OCT-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		45.89		45.89	R	Inappropriate - Refreshments For Meeting
NOV-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		64.44		64.44	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		41.41		41.41	R	Inappropriate - Refreshments For Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		29.44		29.44	R	Inappropriate - Refreshments For Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		38.23		38.23	R	Inappropriate - Refreshments For Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		43.90		43.90	R	Inappropriate - Refreshments For Meeting
MAY-06	0930	Projects	PVS Net - Procard Charges			SOTO'S P/K OUTPOST		91.23		91.23	R	Questionable Expense - Employee Meals
APR-06	0930	Projects	PVS Net - Procard Charges			STEERS AND BEERS		62.56		62.56	R	Questionable Expense - 2 Employee Meals
FEB-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148		14.98		14.98	R	Inappropriate - Refreshments For Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148		23.67		23.67	R	Inappropriate - Refreshments For Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TEXAS LAND & CATTLE#71		71.79		71.79	R	Out-Of-State Expense?
JUN-06	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT #0416		323.26		323.26	R	**Questionable Expense - UNSE Agrees To Remove**
DEC-05	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT 403		30.73		30.73	R	**Questionable Expense - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			TOMATO CAFE		35.30		35.30	R	Questionable Expense - 3 Employee Lunches
FEB-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET		40.67		40.67	R	Inappropriate - Pot Luck For Retirement
MAY-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET		9.37		9.37	R	Inappropriate - Pot Luck For Retirement
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL MART		45.50		45.50	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL MART		36.66		36.66	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1324 SE2		47.55		47.55	R	Office Supplies?
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		24.90		24.90	R	Inappropriate - Gatorade
AUG-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		23.70		23.70	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		41.11		41.11	R	Inappropriate - Gatorade
JUN-06	0930	Projects	PVS Net - Procard Charges			WAL-MART #2051 SE2		262.83		262.83	R	Inappropriate - March Of Dimes
SEP-05	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2		1.78		1.78	R	Inappropriate - Air Freshners For Fridge
FEB-06	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2		25.43		25.43	R	Inappropriate
										28,450.51		

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Schedule RLM-13
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OPERATING INCOME ADJUSTMENT NO. 18
OVERHEAD LINE MAINTENANCE

LINE NO.	ACCT NO.	ACCOUNT DESCRIPTION	(A) COMPANY DATA PER RUCO D.R. 2.12	(B) RUCO ADJUSTMENT PER CPI INFLATION	(C) RUCO ADJUSTMENT
1	593	2003 Year-End Overhead Line Maintenance	$ 334,755	$ 366,775	
2	593	2004 Year-End Overhead Line Maintenance	916,869	978,511	
3	593	2005 Year-End Overhead Line Maintenance	1,136,346	1,173,312	
4	593	2006 Year-End Overhead Line Maintenance	1,010,101	1,010,101	
5		Four Year Total (Sum Of Lines 1 Thru 4)	$ 3,398,070	$ 3,528,699	
6		Average (Line 5 / 4Years)		$ 882,175	
7	593	Test-Year Ending June 30, 2006 Overhead Line Maintenance (Per 2		$ 1,149,853	
8		Difference (Line 6 - Line 7)			$ (267,678)
9		RUCO Adjustment (Line 8) (See RLM-8, Pages 5 & 6, Column (S))			$ (267,678)

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OPERATING INCOME ADJUSTMENT NO. 19
CUSTOMER SERVICE COST ALLOCATION

LINE NO.	ACCT NO.	ACCOUNT DESCRIPTION	(A) UNS GAS AS FILED	(B) ALLOCATION FACTOR	(C) RUCO AS ADJUSTED
1	403	Depreciation Expense	$ 30,202	3.23%	$ (2,156)
2	408	Taxes Other Than Income Tax	33,577	3.59%	(2,397)
3	903	Customer Records & Collection Expenses	633,713	67.71%	(45,230)
4	920	A & G - Salaries	32,869	3.51%	(2,346)
5	921	Office Supplies & Expenses	14,416	1.54%	(1,029)
6	922	Administrative Expenses Transferred	172	0.02%	(12)
7	923	Outside Services	3,307	0.35%	(236)
8	924	Property Insurance	1,717	0.18%	(123)
9	925	Injuries & Damages	379	0.04%	(27)
10	926	Pensions & Benefits	185,531	19.82%	(13,242)
11		TOTAL	$ 935,884	100.00%	$ (66,797)
12		RUCO Adjustment (See RLM-8, Pages 5 & 6, Column (T) For Distribution)			$ (66,797)

Company Determined Allocation Percentages

LINE NO.	2005	UNS GAS	UNS ELECTRIC	TOTAL UES
13	May	20.20%	13.90%	34.10%
14	June	18.90%	13.00%	31.90%
15	July	16.80%	12.20%	29.00%
16	August	15.90%	12.30%	28.20%
17	September	16.40%	13.50%	29.90%
18	October	18.70%	14.70%	33.40%
19	November	19.90%	15.20%	35.10%
20	December	20.70%	15.50%	36.20%
21	Average	18.44%	13.79%	32.23%

RUCO Calculation Of Adjustment

LINE NO.	UNS	MONTHLY COSTS PER RUCO D.R. 2.12 TOTAL UNS	RUCO CALCULATED ANNUAL COSTS	13.79% ALLOCATED TO UNS ELECTRIC
	Pre Consolidation			
22	Estimated UNS Labor and Long Distance:	$ 321,640	$ 3,859,684	$ 532,154
	Post Consolidation			
23	UNS Labor and Long Distance Cost:	$ 362,013	$ 4,344,160	$ 598,951
24	Difference Between Pre & Post Consolidation			$ (66,797)
25	RUCO Adjustment To Test-Year Customer Service Cost Allocation			$ (66,797)

References:
Column (A): Company UNS Gas Workpapers
Column (B): Individual Account Allocation Based On Percentage Of Each UNS Gas Account To Total
Column (C): RUCO Adjustment To Customer Service Cost Allocated By Allocation Factors In Column (B)

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OPERATING INCOME ADJUSTMENT NO. 22
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-7, Column (C), Line 11 + Line 9	$ 13,600,927
	LESS:		
2	Arizona State Tax	Line 11	(577,051)
3	Interest Expense	Note (A) Line 22	(5,319,481)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 7,704,395
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 9	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 2,619,494
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 13,600,927
	LESS:		
8	Interest Expense	Note (A) Line 22	(5,319,481)
9	State Taxable Income	Line 7 + Line 8	$ 8,281,447
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 577,051
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 2,619,494
13	State Income Tax Expense	Line 11	577,051
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 3,196,546
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		1,837,339
16	Difference	Line 14 - Line 15	$ 1,359,207
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 8, Pages 5 & 6, Column (AC))	Line 16	$ 1,359,207

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION	AMOUNT
18	Adjusted Rate Base (Schedule RLM-3, Column (C), Line 16)	$ 128,777,882
19	Weighted Cost Of Debt (Schedule RLM-16, Column (F), Line 1 + Line 2)	4.13%
20	Interest Expense (Line 20 X Line 21)	$ 5,319,481

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Schedule RLM-16

RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) RUCO ADJ'D BILL DETERM'TS	(C) RUCO ADJ'D RATES AND CHARGES	(D) RUCO PROPOSED REVENUE CALCULATION	(E) RUCO PROPOSED REVENUE BY CUST. CLASS
	Residential Service	R-01				
1	Customer Charge per Month		929,088	$ 7.65	$ 7,108,311	
2	Energy Charge, First 400 kWhs		320,682,178	$ 0.01207	3,869,707	
3	Energy Charge, All Additional kWhs		481,023,266	$ 0.02163	10,404,947	
4	Base Power Supply Charge, All kWhs		801,705,444	$ 0.07381	59,173,596	
5	SUB-TOTAL RESIDENTIAL SERVICE					$ 80,556,562
	Small General Service	GS-10				
6	Customer Charge per Month		89,914	$ 11.47627	$ 1,031,878	
7	Energy Charge, First 400 kWhs		36,412,013	$ 0.02656	967,031	
8	Energy Charge, All Additional kWhs		54,618,021	$ 0.03612	1,972,993	
9	Base Power Supply Charge, All kWhs		91,030,034	$ 0.07168	6,524,670	
10	SUB-TOTAL SMALL GENERAL SERVICE					$ 10,496,571
	Large General Service	LGS				
11	Customer Charge per Month		24,301	$ 10.61555	$ 257,969	
12	Demand Charge, Per kW		1,426,880	$ 10.04174	14,328,356	
13	Energy Charge, Per kWh		491,246,281	$ 0.00717	3,522,138	
14	Base Power Supply Charge, All kWhs		491,246,281	$ 0.06347	31,177,289	
15	Total Large General Service				$ 49,285,752	
	Large General Service - TOU	LGS				
16	Customer Charge per Month		120	$ 15.30170	$ 1,836	
17	Demand Charge, Per kW		11,084	$ 10.04174	111,303	
18	Energy Charge, Per kWh		2,903,715	$ 0.00717	20,819	
19	Base Power Supply Charge, All kWhs		2,903,715	$ 0.06347	184,286	
20	Total Large General Service - TOU				$ 318,244	
21	SUB-TOTAL LARGE GENERAL SERVICE					$ 49,603,996
	Large Power Service - < 69KV	LPS				
22	Customer Charge per Month		75	$ 349.06996	$ 26,180	
23	Demand Charge, Per kW		81,047	$ 20.59035	1,668,786	
25	Base Power Supply Charge, All kWhs		41,382,039	$ 0.05040	2,085,812	
26	Total Large General Service - < 69KV				$ 3,780,778	
	Large Power Service - > 69KV	LPS				
27	Customer Charge per Month		69	$ 382.54242	$ 26,395	
28	Demand Charge, Per kW		288,524	$ 11.98314	3,457,424	
30	Base Power Supply Charge, All kWhs		157,244,717	$ 0.05040	7,925,730	
31	Total Large General Service - > 69KV				$ 11,409,549	
32	SUB-TOTAL LARGE POWER SERVICE					$ 15,190,326
	Interruptible Power Service	IPS				
33	Customer Charge per Month		235	$ 10.61555	$ 2,495	
34	Demand Charge, Per kW		63,585	$ 3.34725	212,835	
35	Energy Charge, Per kWh		17,598,914	$ 0.01747	307,466	
37	Base Power Supply Charge, All kWhs		17,598,914	$ 0.05251	924,198	
38	Total Interruptible Service					
39	SUB-TOTAL INTERUPTIBLE SERVICE					$ 1,446,992
	Lighting Dusk To Dawn Service - O/H Service	LTG				
40	Existing Wood Pole		39,277	$ -	$ -	
41	New 30' Wood Pole (Class 6)		8,220	$ 4.30360	35,376	
42	New 30' Metal Or Fiberglass		2,385	$ 8.62633	20,574	
	Lighting Dusk To Dawn Service - U/G Service					
43	Existing Wood Pole		686	$ 2.15180	1,476	
44	New 30' Wood Pole (Class 6)		347	$ 6.46497	2,243	
45	New 30' Metal Or Fiberglass		7,646	$ 10.77813	82,410	
46	Per Watt		7,866,778	$ 0.05956	468,567	
48	SUB-TOTAL LIGHTING DUSK TO DAWN SERVICE					$ 610,646
49	TOTAL REVENUE PER RUCO BILL DETERMINENTS					$ 157,905,093
50	Sales For Resale					246,016
51	Other Operating Revenue					1,637,662
52	TOTAL PROPOSED REVENUE					$ 159,788,771
53	Proposed Annual Revenue Requirement					$ 159,788,771
54	Difference					$ 0

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)	(E)	(F)
		PRESENT REVENUE		COMPANY PROPOSED		RUCO PROPOSED	
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 81,247,060	51.48%	$ 84,232,815	51.02%	$ 80,556,562	51.02%
2	OTHER	$ 76,580,097	48.52%	$ 80,878,384	48.98%	$ 77,348,532	48.98%
3	TOTAL	$ 157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	7,403,038	4.69%	8,989,479	5.44%	$ 8,597,143	5.44%
5	VARIABLE REVENUE	150,424,119	95.31%	156,121,720	94.56%	$ 149,307,951	94.56%
6	TOTAL	157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	RESIDENTIAL RATE DESIGN	PRESENT RATES		COMPANY PROPOSED		RUCO PROPOSED	
	Residential Service - Mohave County						
7	Customer Charge per Month	$ 6.50		$ 8.00		$ 7.65	
8	Energy Charge, First 400 kWhs	$ 0.07490		$ 0.0126178		$ 0.01207	
9	Energy Charge, All Additional kWhs	$ 0.07490		$ 0.0226180		$ 0.02163	
10	PPFAC Charge	$ 0.018250					
11	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.07381	
	Residential Service - Santa Cruz County						
12	Customer Charge per Month	$ 6.50		$ 8.00		$ 7.65	
13	Energy Charge, First 400 kWhs	$ 0.07930		$ 0.0126178		$ 0.01207	
14	Energy Charge, All Additional kWhs	$ 0.07930		$ 0.0226180		$ 0.02163	
15	PPFAC Charge	$ 0.018250					
16	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.07381	

LINE NO.	**RESIDENTIAL BILL COMPARISONS** MONTHLY ELECTRIC BILLS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	% OF AVERAGE MONTH USAGE OF 10,334 kWh	ACTUAL MONTH USAGE OF 10,334 kWh	PRESENT MONTHLY COST	RUCO PROP'D MONTHLY COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
	Residential Service - Mohave County						
17	Customer Charge per Month	25.00%	2,584	$ 247.15	$ 250.40	$ 3.24	1.31%
18	Energy Charge, First 400 kWhs	50.00%	5,167	$ 487.81	$ 496.97	$ 9.16	1.88%
19	Energy Charge, All Additional kWhs	100.00%	10,334	$ 969.11	$ 990.11	$ 21.00	2.17%
20	PPFAC Charge	150.00%	15,501	$ 1,450.42	$ 1,483.25	$ 32.83	2.26%
21	Residential Service Base Power Supply Charge, All kWhs	200.00%	20,668	$ 1,931.72	$ 1,976.39	$ 44.67	2.31%
	Residential Service - Santa Cruz County						
22	Customer Charge per Month	25.00%	2,584	$ 258.52	$ 250.40	$ (8.12)	-3.14%
23	Energy Charge, First 400 kWhs	50.00%	5,167	$ 510.54	$ 496.97	$ (13.57)	-2.66%
24	Energy Charge, All Additional kWhs	100.00%	10,334	$ 1,014.58	$ 990.11	$ (24.47)	-2.41%
25	PPFAC Charge	150.00%	15,501	$ 1,518.62	$ 1,483.25	$ (35.37)	-2.33%
26	Residential Service Base Power Supply Charge, All kWhs	200.00%	20,668	$ 2,022.66	$ 1,976.39	$ (46.27)	-2.29%

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 5,000	$ -	$ 5,000	3.97%	6.36%	0.25%
2	Long-term Debt	$ 59,486	$ -	$ 59,486	47.18%	8.22%	3.88%
3	Preferred Stock	N/A	$ -	$ -	0.00%	0.00%	0.00%
4	Common Equity	$ 61,587	$ -	$ 61,587	48.85%	9.30%	4.54%
5	TOTAL CAPITAL	$ 126,073	$ -	$ 126,073	100.00%		
6	WEIGHTED COST OF CAPITAL						8.67%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, WAR
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital (L5)
- Column (E): Testimony, WAR
- Column (F): Column (D) X Column (E)